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Cover Image: View of construction of Gulf Coast Growth Ventures ethane cracking and derivatives complex in San Patricio, Texas (U.S.). This project was awarded the Top Petrochemicals project of 2021 by readers of *Hydrocarbon Processing*. Photo courtesy of Gulf Coast Growth Ventures.

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HP Industry Perspectives

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As petrochemicals demand/capacity increases, sustainable targets grow in importance

Although most forecasts show global oil demand leveling off within the next decade, nearly all forecasts show a surge in petrochemicals consumption to 2050. In fact, a significant portion of global oil demand increases over the near term is in response to needed feedstock to produce petrochemicals. For example, the International Energy Agency forecasts naphtha and LPG/ethane demand for petrochemicals production to increase by 1.2 MMbpd and 900,000 bpd, respectively, by 2027. The much-needed supplies of LPG/ethane and naphtha will provide feedstock to produce petrochemicals in great demand now and in the future.

Capacity buildout. The expected increase in petrochemicals demand has led to significant investments in new petrochemical capacity builds in Asia and other regions around the world.

According to Gulf Energy Information's Global Energy Infrastructure (GEI) database, petrochemical projects represent more than 35% of total active projects globally. By 2030, there could be more than 3 Btpy of petrochemicals production capacity globally (**FIG. 1**).

Integration, addition and greening. The need for more petrochemicals has increased the development of mega refining and petrochemicals integrated complexes. This has been a major development trend primarily in Asia, especially in China, where the GEI database is tracking more than $60 B in integrated complexes construction.

Many other companies are investing in incorporating new petrochemicals production capacity into existing refining operations. For example, India is developing both integrated refining and petrochemical complexes but is also investing billions in adding new polymer production capacity into domestic refining operations. The Middle East continues to do the same.

The additional petrochemicals capacity will also increase carbon dioxide (CO_2) emissions. Much like other hydrocarbon processing sectors, the global petrochemicals industry is also investing in new technologies and processes to mitigate carbon emissions, as well as incorporate new biofeedstocks and materials to produce "green" petrochemicals.

The focus on sustainable operations and production is a major aspect of this issue's Special Focus section on Petrochemicals Technology. These articles provide novel approaches to enhance operations, while helping to adhere to sustainability goals. **HP**

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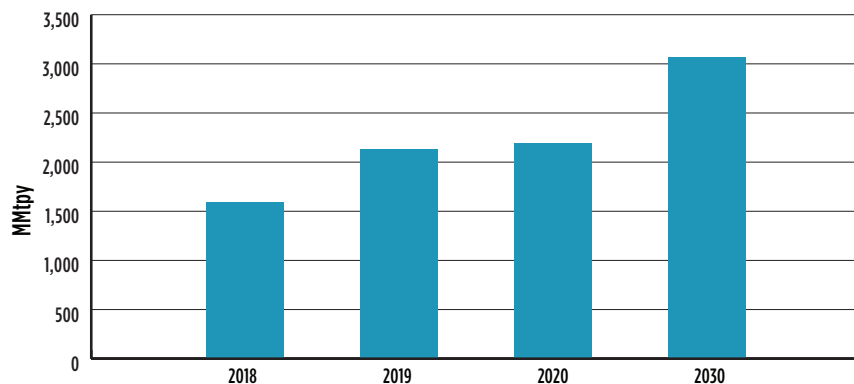

FIG. 1. Petrochemicals production capacity worldwide (MMtpy), 2018–2030. Source: Statista.

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HP Business Trends

The big data tools and related professional competencies required in the chemical industry

Big data is making tremendous changes in various sectors of the economy, and chemical industries can now leverage these new advancements. Companies in the chemical industry are starting to realize how they can create additional value from the vast amounts of data they have, and how this data can be efficiently used to make more effective and strategic decisions. However, to leverage this data, there is a need for timely investments in big data projects, including investing in big data competency training and in tools for scalability.

Engineers must understand data science, and how to take command over coding and develop a strong quantitative aptitude. Various big data tools are available on the market that can make big data integration easy by providing a unified platform for the collection and arrangement of information extracted from big data. This article will focus on the competencies and tools necessary to make the investment for big data adoption. It will also review present and future big data adoption challenges, and highlight how entities (such as government, academia and industry) must collaboratively work together to overcome them.

What is big data? Big data is a vast amount of data of a dissimilar nature that is produced through various sensors in the chemical industry, and this data requires a large volume of storage space and specialized tools for processing. Big data can enable engineers to enhance their analyzing capabilities by providing them with vast amounts of accurate and real-time information from many sources. This also requires visualization and storage tools that can provide them the facility to store their data, and to analyze and forecast the outcomes of their processes. Big data is espe-

cially helpful for engineers in the chemical industry, as their work is highly complex and deals with a huge amount of data beyond human capabilities. Engineers are continuously in need of a source that provides them with access to a high volume of data to perform necessary analyses. More data is generated following these analyses; hence, it is important for engineers to store this data to keep a record of simulations and modeling for further optimization and forecasting.

Big data in the chemical industry. The chemical industry requires hardware that can process complex algorithms for multivariate analyses to support decision making. The industry also needs to invest in big data tools and related professional competencies. In the past, traditional engineering did not include such skills and advanced technologies as part of a higher-education curriculum. This is now changing, as these competencies have become more relevant in the modern big data era.

Traditionally, engineers manually make the correlations, identify the relationships in variables, and design hypotheses for limited variables. The challenge is to shift engineers from these conventional methods to the big data era so that all analyses can be done through automated systems with higher accuracies for multivariate analysis.

In the past, it was difficult for the chemical industry to successfully implement the latest technologies in its operations because of the complexity of the domain and the additional prerequisites for the necessary technology integration. However, big data is different from conventional advancements because of the increased awareness and available tools in the market. Through its industry-wide adoption and integration, big data can increase the competitive capabilities of the chemical industry.

Big data scalability. Scalability in the chemical industry is the ability of available systems to grow in response to changing demands for big data adoption. For example, this may include computing and networking, in addition to human resource requirements.

Big data is easily scalable, which allows companies in the chemical industry to adjust the data according to their changing demands. This means that big data contains a large volume of data that is reliable and verified through various platforms that have already been implemented. This includes data from various systems, such as process and management information systems.

Data may contain different versions, including text and video content, in addition to several forms of numerical data from sensors. Obviously, engineers cannot use all this data, as they rely on accurate data that is relevant to their field and processes. If scalability is not considered, then the outcome of the company's big data utilization, along with the benefits that it can provide, could be diverted from the engineers' expectations.

For the successful utilization of big data in industry, it is necessary for engineers to have strong analytical tools. Quality will suffer if the scalability is not correctly adjusted. This can raise questions on the competitive capability and on the overall stakeholder satisfaction for these tools, and can risk their profitability. Scalability is not as simple as it appears, and requires careful consideration of the following factors:

- **Random access memory (RAM) status.** This is the most critical component often ignored by companies in the adaptation of big data. It is linked with the capacity of the servers and computers

to accept and continue the data communication. For the processing of analytics used by chemical engineers, it is necessary for engineers to have servers that do not disrupt the information flow of the application. Companies can easily upgrade RAM memory to reduce challenges.

- **Disk storage capacity.** Disk storage space is also an important factor and is required for analytics by big data tools. Systems must have sufficient disk storage to both install and operate the required big data tools without disrupting operations. Big data tools use algorithms that require a lot of disk space to run many iterations and models to arrive at the optimum solutions.

- **Central processing unit (CPU) consumption.** Big data tools can be CPU processor hungry, especially when running several solutions simultaneously, which can slow down processing. There can be times when the highest CPU usage is required for several solutions, thus impacting other processes that require CPU usage. Therefore, in the chemical industry, it is important for big data tools to be applied to systems with sufficient CPU processing power.

Scalability can be beneficial, but it is equally important to understand the necessity for it. Despite its significance, each company has a specific situation and need for scalability. Scaling is required when the company is facing problems of downtime and slow performance. Scaling is a better choice (rather than allowing the problem to become a major hurdle) for adapting new technologies related to big data. High latency can be the signal for the right time for scalability. There are scaling-up systems that can be adjusted based on criteria required for data.

Scalability is not only limited to adjusting the volume of information by setting a criterion, but it also includes the initiatives related to big data, such as big data analytics and infrastructure. All the elements and factors related to big data are needed for the system to be scalable, so they can easily reach the desired target without wasting resources. The big data tools available in the market enable companies to scale the infrastructure in both horizontal and vertical directions. Adopting big data tools and replacing conventional methods may enable a facility to scale its existing analytical tools.

Big data tools enable a systematic approach for engineers to work together. There will be a point when the need to scale the number of workers will be felt. Here, scalability will help to scale human resource requirements efficiently and effectively. Investing time in, and paying attention to, the scalability of the analytics team to determine the team size that is capable of meeting demands can provide long-term benefits to companies in the chemical industry.

Cloud computing platform. The major reason for big data technology evaluation is to enable engineers to solve complex problems. They are expected to consistently obtain reliable, repeatable, highly accurate and precise solutions for complex problems, which requires a high degree of computational power.

Investing in a cloud-based computing platform can help address these challenges. This type of platform will contain a collection of servers that are able to support big data analytics. Cloud computing is a powerful technology that provides remote access to the database and analytics through the internet. It is beneficial because it solves the problem of data storage and CPU limitations when utilizing big data tools. This is especially true for engineers that will use big data tools for complex problem-solving algorithms that require higher computational power.

Another benefit of utilizing a cloud platform is cost savings. This is because the service provider will be liable for the security and maintenance of the platform. Users only have to pay for the service provided by the company. The cloud service provider also ensures the availability of virtual resources. There is no need to purchase, maintain, expand or replace hardware when a cloud-based service can be purchased on a pay-as-you-go basis.

The mining algorithms are easily processed by virtual resources. Also, many vendors and contractors can be given access to the cloud for real-time feedback. Normally, computer systems available to engineers are insufficient to process the amount of data and to manipulate the size of algorithms. Therefore, there is a need for cloud-computing technologies that have easily scalable architecture specifically designed for big data. Such systems that can meet these industry requirements are still in development.

Data specialization. In the complex chemical industry, the role of data scientists and big data specialists cannot be ignored. They play an important part in the successful integration of big data in the chemical industry. The data scientist can understand paradigms of information processing and can shift the conventional model to a big data-driven approach.

Another critical role for data scientists is data mining. Data scientists can assist in collecting data and extracting the required logic from it. Data collection, analysis, interpretation, management and arrangement are equally important. It is mandatory for data scientists to convert the data into synchronized patterns, so that the data has a visible trend and can prove a hypothesis.

The chemical industry cannot deny the importance of big data specialists. A big data specialist is a data scientist with domain knowledge and experience specific to the chemical industry. There can be situations when data scientists have specialized knowledge of big data and the know-how about its integration. However, this is not always the situation. A big data specialist is needed for interrogating, understanding and handling large groups of data. There is a significant difference between the job of a data scientist and a big data specialist. The nature of a data scientist is to understand the given data and to use it in a favorable form, while the big data specialist has chemical industry domain knowledge and is familiar with the pattern of big data, making it available for the data scientist. Therefore, it is necessary for companies to invest in both big data specialists and data scientists to successfully integrate big data in chemical engineering.

The best way to overcome these challenges is to scale chemical engineers as data scientists and big data specialists through university courses and/or professional training.

Big data professional competency. Despite the latest big data tools and availability, the chemical industry cannot deny the need for workforce development for the successful integration of big data. Having traditional knowledge and using con-

ventional tools are not enough for the successful utilization of big data. Integrating big data requires a specialized approach, an understanding of programming languages and advanced analytic skills. It is very important for engineers to make the right decisions at the right time, so they must have the right skillsets to accomplish this. The following are some workforce developments required in the chemical industry:

• **Programming language.** It is not sufficient to hire chemical engineers and simply ask them to integrate big data into their operations. It is necessary to invest in programming and development areas. There is a need for big data developers who can understand the function of big data technologies, and to use their knowledge to address chemical engineering issues. Necessary programming language skills include Apache Spark, Hadoop with Python and Java.

When engineers have an in-depth competency of programming, they can easily divert it into a wider scope demanded by big data. Having strong programming language and domain competencies can save the industry from the problems created by an enormous volume of big data. While these challenges are difficult to tackle with the restricted amount of funds available to the industry, investments in programming languages are needed. For the implementation of big data in the chemical industry, engineers must integrate big data tools into their legacy software. Normally, the respective programming language provides a library facility that makes it easier for engineers to perform their required big data analytics.

• **Quantitative aptitude and statistics.** The competency of quantitative aptitude is necessary to understand big data and interpret it in the desired situation. It is necessary for the company to invest in the quantitative aptitude of the people handling big data. In addition to having the required technology, it is equally important to have a command over linear algebra and statistics. Big data analytics is heavily dependent on statistics,

and this demand can increase from simple to complex statistical methods, depending on the project. This statistics literacy is necessary because the algorithms used to make the programming language are based on statistical rules and fundamentals. Therefore, having a command over statistics, other than just domain knowledge, is equally important for the integration of big data.

Companies in the chemical industry often create teams of chemical engineers and statisticians to meet these needs, but these two jobs can be done by just one person to reduce the cost of big data integration. For big data integration, data scientists, statisticians and chemical engineers are working together to avoid security problems in the long run. Today, chemical engineers need to have data science application skills, which are not presently taught in universities, and companies can provide these skills through a comprehensive employee education program.

• **Machine learning (ML).** For chemical engineers, the need to invest in programming cannot be mixed with the significance of ML—and its subset known as deep learning. Most companies outsource the job of ML. However, the integration and application of big data becomes easy and effective when a company has integrated ML techniques and chemical engineering competencies. The complex multivariate diagnostic and prediction problems that chemical engineers face is simplified by ML, which includes models such as regression, decision trees and neural networks. Chemical engineers provide timely, accurate and precise solutions to maximize profit. ML techniques enhance this by making the path to achieving the required solution more efficient. If engineers have ML knowledge, which is a part of data science, then they can perform operations at a safe level and, consequently, maximize profit values.

• **Process monitoring.** Chemical engineering processes are sometimes complex and long, requiring a full-

time person to monitor and observe them. This task can be done with big data tools. Chemical engineering demands predictive, descriptive, diagnostic and prescriptive activities when monitoring these processes. When companies invest in the skill of data science for their chemical engineers, these engineers will be able to provide exploratory data analysis (EDA), and this analysis will revolve around making conclusions and extracting valuable insights from the data. It will automatically cover statistical literacy. Engineers will also be capable of using descriptive and visualization statistics as a tool for big data analytics. EDA will help companies identify solutions that will have the biggest contributions to profitability.

Takeaway. For the successful integration of big data, it is necessary to have the right big data scalability and professional competencies. By making investments in big data scalability factors and acquiring big data competencies, engineers working in the chemical industry will be able to capitalize on the enormous amount of data and to utilize this data for solution development.

The chemical industry needs tools that can collect the desired information in a single platform from multiple sources and provide a facility to arrange it. After having the desired skill set and architecture, the chemical industry must invest in big data tools that meet industry requirements. The chemical industry should drive the switch from conventional analytical methods to big data-driven approaches. **HP**

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HP | Global Project Data

Gulf Energy Information's Global Energy Infrastructure database is tracking nearly 1,100 projects around the world, totaling more than $1.8 T in active capital project investments. At more than 400 projects, the Asia-Pacific region is by far the leader in total capital projects. The region is investing nearly $750 B to increase refining, petrochemicals and gas processing/LNG capacity to meet burgeoning demand. Following Asia in total active projects is Eastern Europe, Russia and the CIS region, and the U.S. Most projects in Eastern Europe are in Russia, as the country continues to build new LNG export infrastructure and polymers production capacity. HP

28 Canada
57 Western Europe
148 Eastern Europe, Russia, CIS
124 U.S.
90 Africa
118 Middle East
413 Asia-Pacific
51 Latin America
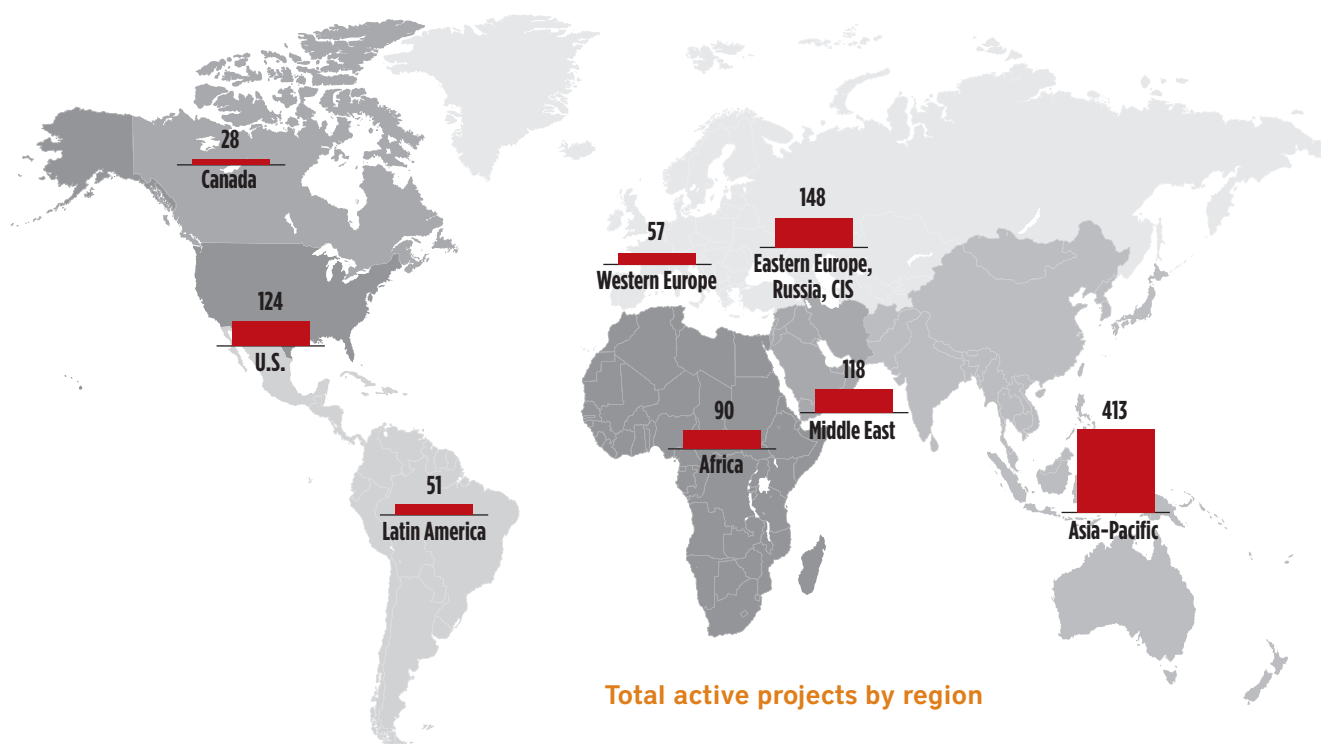
Total active projects by region

New project announcements:
Dec. 20: 16
Jan. 21: 17
Feb. 21: 21
March 21: 24
April 21: 35
May 21: 32
June 21: 20
July 21: 17
Aug. 21: 10
Sep. 21: 15
Oct. 21: 23
Nov. 21: 10
Dec. 21: 10
Jan. 22: 12
Feb. 22: 13
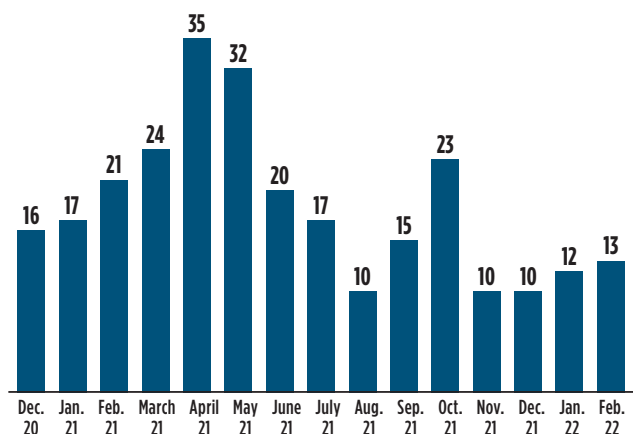
**New project announcements,
December 2020–February 2022**

9% Africa
12% U.S.
40% Asia-Pacific
11% Middle East
5% Latin America
14% Eastern Europe, Russia, CIS
6% Western Europe
3% Canada
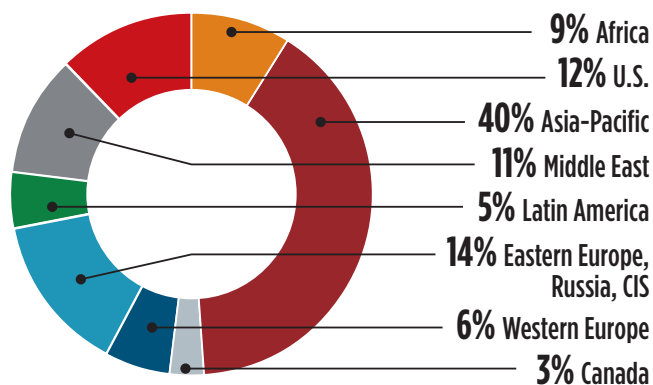
Total active project market share by region

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Use available database to assist in compressor design audits and selection

Over the last 40 yr, centrifugal compressor manufacturers have compiled a vast array of impellers and associated stationary components, allowing for higher efficiency staging. Within this array, different families of impellers and stationary parts allow application engineers to make selections to match various process conditions. They have achieved this through newer and more sophisticated machining technologies, and by consistently using more accurate computational fluid dynamic (CFD) analyses. However, even with these advanced technologies, the matching of internals such as diffusers and return channels with new and improved impellers can be difficult. In instances where trial and error must be used, the end results will be accurate, but it will take time to get there. Geometric scaling is still the common scale-up technique—it makes use of similitude or proportionality principles.

FIG. 1 shows two trend lines of head per stage vs. molecular weight obtained during a 40-yr period of data mining. The database covers molecular weight applications ranging from 4 to 104, using compressors from different manufacturers. These trend curves have been extremely helpful in the past as a rapid checking tool for proposals from various compressor manufacturers. Both new and revamped (re-rated, upgraded) compressors are represented in **FIG. 1.**

To reconfirm—for the most part, compressor manufacturers do get it right when matching stages to process conditions. However, problems arise when scaling is used to extrapolate stages outside the vendor's normal experience or comfort zone without proper CFD validation techniques. Therefore, user-purchasers must check a manufacturer's proposed staging when purchasing centrifugal compressors. The purchaser should ensure that compressor manufacturers submit experience lists for these stages. Alternatively, or if the user has data from past purchases, in-house experience could be utilized. Early delivery of the compressor train, field erection with attention to the proper placement of temporary but fully approved measuring instruments, and full-scale field testing are often possible and should be on the purchaser's list of options.

Trend line A-B indicates compressors manufactured pre-1990, and trend line C-D is for compressors manufactured post-1990 to about 2019. Points E and F were obtained from two case histories where the compressor manufacturer initially did not perform proper CFD to match the high-coefficient impellers. Several iterations had to be done using high-fidelity CFD techniques to match the stationary internal components with the proposed impeller.

Over the years, trend lines A-B and C-D have shown that if a compressor manufacturer's compression stage design fits on
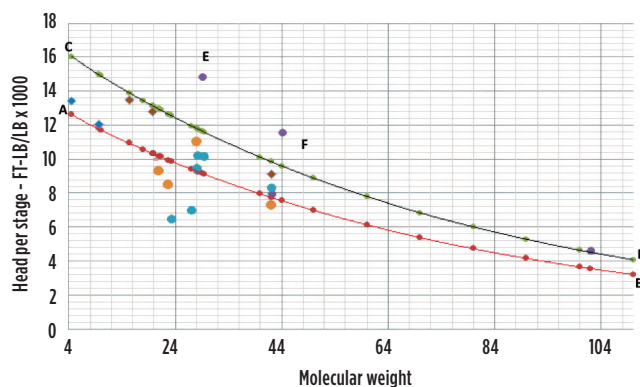
FIG. 1. Head per stage vs. molecular weight curves obtained during 40 yr of data.

or below these lines, the compressor will likely perform as designed. These lines are considered suitable audit tools to either have confidence in a proposed offer or to raise questions on the compressor manufacturer's proposed staging. However, these lines are not considered fool-proof and should only be used to raise questions when designs deviate from the lines.

Experienced third parties are sometimes brought in to assess certain risks or to assist in resolving different opinions before they become more serious disputes. Engaging in structured machinery quality assessment (MQA) will be of great benefit to the user-purchaser.[1]

It has been established that budgeting an additional 5% of the cost of critically important process machines to fund MQA activities pays back handsomely. The tendency of an MQA to catch vulnerabilities before they reach the field is the primary reason for a facility to be later counted among the best-in-class performers. **HP**

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Staying ahead of environmental, social and governance goals

Investing in firms that champion environmental, social and governance (ESG) issues (**TABLE 1**) has been discussed for decades but is now moving to the forefront of corporate initiatives. ESG may have transitioned to reality in 2004 when the United Nations Secretary, Kofi Annan, asked 50 major financial institution Chief Executive Officers to join an initiative for finding ways to integrate ESG concepts into global markets. The term ESG was coined a year later in a report that explained how championing ESG factors made good business sense, created sustainable markets and benefited society.

Since that time, the movement has gained traction, with many investors and stakeholders actively demanding that companies engage in ESG improvements and publicly show their progress in key areas. The calls have been so great that the U.S. Security and Exchange Commission (SEC) is creating reporting guidelines so companies can provide consistent and accurate accounts of their ESG programs, alongside their standard financial reports.

Strong ESG performance is rapidly transitioning from a differentiator to a requirement for many corporations. Even though the standards and guidelines are not yet fully written, a wise company is already formulating meaningful goals and showing ESG improvements to proactively address issues.

ESG in the oil and gas industry. While social and governance issues apply to nearly all companies, petrochemical companies are naturally more focused on environmental issues. There is a great deal of public pressure on the industry to decarbonize product streams and reduce emissions of pollutants, especially greenhouse gases (GHGs). To accomplish these goals, most firms are utilizing a multipronged approach (**FIG. 1**).

One major initiative is the use of re-cycled and renewable feedstocks to create low-carbon alternative fuels. Such feedstocks might include soybean oil, corn oil, beef tallow, white grease and used cooking oils, as well as oils from algae, rapeseed and carinata. Other processes collect biogas from various agricultural and waste sources and then convert those potential GHG emissions to saleable biomethane for injection into natural gas pipelines.

Another source of environmental improvements comes from the reduction of intentional and fugitive methane emissions. Remote oil and gas production areas and pipelines often use natural gas as a motive force for instrumentation and valve actuation, and methane is vented with each stroke or bled continuously. Also, most control valves and/or pumps in chemical service tend to emit pollutants through packing and seal leaks. All these emissions sources can be substantially curtailed and even eliminated through proper equipment design, replacement with electric actuators or improved packing designs.

In addition, advanced controls tactics and strategies offer numerous ways for processing facilities to improve yields and run more efficiently, while reducing waste and emissions.

ESG improvements through automation. Like oil and gas companies, many automation industry firms are also

TABLE 1. Increasingly, activists and investors are demanding companies focus on ESG issues, make goals and show continual progress and improvements
Environmental
Reducing greenhouse gas emissions
Tracking environmental footprint
Energy source decarbonization: Supporting low-carbon commitments
Emissions management
Collaborating with universities around the world
Protecting food quality and environmental sustainability
Social
Enabling safety and security
Workplace safety
Diversity, equity and inclusion
Employee engagement
Training and development
Training the workforce of the future
Advancing the future of communities
Science, technology, engineering and mathematics (STEM) education
Governance
Board diversity and structure
Corporate governance actions
Risk management and oversight
Integrity and ethics

pursuing multiple ways to reduce emissions. Most have initially focused on internal processes, such as building/energy improvements, improved manufacturing efficiency and a reduction in manufacturing waste and water usage. While these methods certainly have a positive impact on the environment, the most dramatic environmental improvements come from the development of new instrumentation and controls, which enable oil and gas companies to achieve their ESG goals in a more effective and less costly way.

Membrane technology, automated controls and advanced analytics have facilitated the installation of hundreds of biomethane processing and injection facilities all over the world.

The falling cost and improved performance of biogas processing units allow landfills, chicken and pig farms, and wastewater and food waste facilities to profitably convert their GHG emissions to market quality natural gas. The processes required use anaerobic digesters and self-contained biomethane processing/injection skids.

Another enabler of significant GHG emissions reduction are new designs in valve actuation that allow natural gas-actuated valves to be replaced with low and even zero-emissions alternatives. Often sold as retrofit kits, these relatively inexpensive instrumentation upgrades provide dramatic reduction in methane and GHG emissions.

> **Many investors and stakeholders are actively demanding that companies engage in ESG improvements and publicly show their progress in key areas. Strong ESG performance is rapidly transitioning from a differentiator to a requirement for many corporations.**

Additionally, some automation suppliers offer a variety of low-bleed alternatives for natural gas-powered instrumentation, as well as very low power electrical alternatives, which can run on the power provided by small solar systems.

In many cases, the savings generated from the reduced methane emissions, reduced testing requirements and additional natural gas production pay for the instrument upgrade. All this equipment meets the much more stringent methane emissions regulations recently passed in the U.S. and Canada.

Other recent product developments include zero-leakage knife gate valves for applications with hazardous materials, along with significant improvements in valve design and valve packing designs.

These design innovations help the industry make significant strides in the reduction of hazardous liquid and gas emissions to the environment, even as they reduce maintenance costs and improve process efficiency.

Maximizing ESG progress through collaboration. While both oil and gas industry and automation suppliers are making significant strides towards achieving their environmental goals, best progress often results from a collaboration between these two groups. This is already happening in some areas, with oil and gas specialists working with automation leaders to address the most pressing challenges by designing innovative methods to address ESG issues.

Another area of collaboration can be found in joint partnerships between automation leaders and universities. Automation suppliers routinely fund sustainability forums, award grants and provide scholarships to further research in a variety of environmental fields. These efforts often result in next generation instrumentation and chemical processes, yielding significant environmental improvements.

Act now. The demands from shareholders, stakeholders, the U.S. SEC and the public for improvements in ESG initiatives are becoming insistent. Rather than wait for new regulations to be issued, most industry leaders are staying ahead of the curve by defining their own goals, tracking progress and publishing results. There are multiple benefits to this approach.

Improvements immediately benefit society and the environment, but they also allow a company to define its role and choose the best path forward to meet ESG goals. That option is almost always preferable to having governmental entities dictate goals and define required methods.

The most successful outcome for our planet results from collaboration between industries. Oil and gas companies may find it worthwhile to explain their environmental goals and operational challenges to their automation suppliers so they can suggest specific solutions and adjust product roadmaps. These types of collaborative efforts are already underway, with benefits being realized now, and more to come in the near future. **HP**

FIG. 1. Most oil and gas companies pursue a broad variety of methods to reduce GHG generation and emissions.

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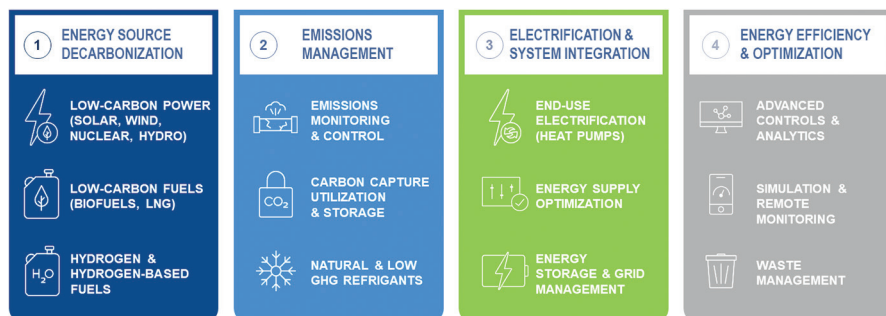
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Building resilience: Why now is the time to invest in natural hazard risk management

With extreme weather events growing in frequency worldwide, organizations can do many things to protect their assets and mitigate some of the risks posed by natural hazards.

From raging wildfires in Australia at the beginning of 2020 to the catastrophic flash flooding across much of Europe in July 2021, various natural hazard events in recent years have destroyed property and infrastructure, devastating businesses and taking lives.

In the U.S., Hurricane Ida brought back painful memories to the people of New Orleans, Louisiana. The city is still rebuilding after Hurricane Katrina caused 1,800 deaths and $125 B of damage in 2005.

Unfortunately, natural disasters like hurricanes, cyclones, storms, floods and wildfires are occurring more often and with greater severity. This can be viewed in terms of economic cost increases over time.

The Asia-Pacific region tells a similar story. Here, average annual disaster event-induced economic losses between 2000 and 2009 stood at $56.7 B. For 2010–2019, that figure more than doubled to $117.9 B. The Tohoku Earthquake, which struck Japan in 2011, is largely responsible. Still, even when removing 2011 from this period, the nine remaining years averaged $89.1 B in annual natural disaster damage.

Counting the cost. These concerning figures translate into a multitude of damages encountered by organizations that operate across various industries, including oil and gas, refining, petrochemicals, energy, chemicals, technology and other industrial sectors with large and highly valuable infrastructure bases. Unplanned outages and economic losses from production downtime are major consequences of the disruption caused by extreme weather events.

Additionally, many secondary and tertiary social and environmental impacts stem from the primary damage done to these businesses.

So, why are power and chemical plants particularly affected by natural disasters?

Geography plays a critical role here. For instance, many petrochemical facilities are strategically located close to coastal and inland waterways to enable easy transportation of goods in and out of their sites.

However, this makes them particularly susceptible to hurricane and flood risks. For example, in the U.S., many plants and industrial sites are located near the Gulf Coast, Atlantic Coast and Mississippi River. Earthquakes are another risk factor, primarily in the western states and other regions near fault lines. Key risk areas in Europe include sites along rivers and coasts, including those in areas at or only slightly above sea level.

Prior to COP26, there was a great sense of urgency among key political decision-makers, enterprises and wider society. Hosted in Glasgow, Scotland, UK, the summit represented a defining moment for Britain's Prime Minister, Boris Johnson. His government pushed ahead with some of the most ambitious climate targets ever pledged by a UK government.

However, enterprises should not wait for more comprehensive legislation and regulations to impel them into action.

Few or no global regulatory drivers aimed at industrial facilities require (or assist) them to withstand extreme weather events. The onus is on organizations to determine their own natural hazard risk management strategy—given the growing frequency of these incidents, the time to act is now.

Approaching natural hazard risk management. The extent and nature of such actions depend largely on each business's appetite for risk, i.e., the extent to which a business is prepared to deal with disruptions caused by storms, hurricanes, wildfires, floods and other extreme events.

Direct concerns may include the reliability and resilience of the organization's equipment, insufficient worker safety protocols and unplanned outages.

However, it is also important to consider that physical damage to buildings and equipment represents only the initial source of financial loss.

Resultant business disruption and market displacement can also significantly affect revenue figures, depending on the severity of the natural hazard in question. Concerns here can center around storing materials, disruption to feedstock supply, transportation availability/access and cost/availability of energy.

To help quantify some of these risks, organizations should consider various factors.

How much revenue will be lost if the facility is shut down for an extended period? Can an additional understanding of the risks help the company to manage operations? Will improvements to preparedness and response reduce direct damage and limit revenue loss following an extreme weather event?

Considering these questions is an excellent place to start: the answers may prompt a series of potential mitigation measures. Facility hardening, enhanced preparedness/response planning and organizational measures to limit the impact of any single extreme event are among the risk-mitigating steps companies can take, along with acquiring insurance policies.

Another option is to leverage the expertise of third parties in engineering and risk management.

Independent risk assessments and audits can serve as vi-

tal tools in quantifying actual risks, with engineering-based studies revolving around rigorous site-specific technical assessments that enable facilities to measure their exposure to numerous natural hazards. This can carry advantages over advice and subsequent cover offered by insurance firms, which may not provide this level of rigorous evaluation and technical understanding.

Regardless of what approach is taken, companies are advised to build risk into their cost of business and plan for a certain degree of extreme weather disruption every year.

Providing a helping hand. Some organizations may lack the in-house technical and engineering expertise to properly plan and execute an entire natural hazard risk management strategy.

Expertise in process safety (including accidental hazards such as fires, explosions and toxic spillages) and structural engineering is critical for companies to get support from initial design and throughout a facility's lifecycle.

Specific services, such as risk assessments and independent audits, equipment elevation audits (flood risk), natural hazard audits (from backup power systems to data protection), flood and storm surge risk analyses, reviews of emergency response plans and natural hazard risk management toolkits, offer insights and resources to assist industrial facilities in reducing their exposure to natural and artificial hazards. Knowledge sharing is crucial if organizations with assets prone to natural hazard risk are to futureproof themselves effectively.

In the UK, several conference papers were planned for the Hazards31 conference in November 2021 that focused on process safety issues.

Here, flooding is the most frequent and damaging natural hazard, the risk of which is growing due to climate change and the increasing regularity of extreme weather events. These conference papers examined vital lessons learned and how to navigate the UK's Control of Major Accident Hazards (COMAH) regulations.

With more industrial businesses throughout the UK, Europe and other regions around the world being impacted by natural hazards, the clear message is that risk from natural hazards is growing. As climate change produces extreme weather events that may become more frequent and severe, the time to act is now. **HP**

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Enhance aromatics production with concurrent reduction of environmental footprint–Part 2

Part 1 of this article (October 2021) discussed how catalytic reforming processes produce olefin contaminants in aromatics streams via paraffin dehydrogenation side reactions. Operating catalytic reformers at higher severity results in higher yields of valuable aromatics, but it also results in higher olefins content in the reformate. Olefins must be removed from C_6–C_7 aromatics streams to meet benzene product specifications, and from C_8+ aromatics streams to meet specifications for paraxylene recovery processes.

That article presented key features and performances for the olefins selective hydrogenation process, and options for its implementation in an aromatics plant block flow diagram. It also described the benefits of selective hydrogenation addition to an existing facility. The benefits of selective hydrogenation integration in a grassroots facility will be addressed here.

Olefins selective hydrogenation integration in the aromatics block of a crude-to-chemicals complex. The most significant benefits achieved by adding an olefins selective hydrogenation process to an existing aromatics complex have been recently described[1] and can be summarized as:

- End the downgrade of valuable aromatic molecules to fuel oil in the process of removing olefins
- Yield additional valuable aromatic molecules by hydrogenation of alkenyl aromatics
- Lower the environmental footprint of aromatic plants by considerably reducing solid waste production.

Furthermore, process selectivity—that is, olefins hydrogenation without loss of aromatic rings—is key to additional aromatics production.

Material balance improvements are incremental; they can be very substantial for smaller existing sites, but they become of immense proportion when olefins selective hydrogenation is part of the aromatics section design in a new crude-to-chemicals (CTC) complex, due to the large production capacity of these facilities. Similarly, the environmental benefits are massive, as the generation of millions of kilograms (kg) of clay waste can be avoided every year.

The olefins selective hydrogenation unit can be integrated upstream from the reformate stabilization column for maximum advantages. In this configuration, the full reformate stream is processed, yielding the following benefits:

- The reduced olefins content in the feed to the extraction unit results in lower solvent and energy consumption for the extraction process
- Aromatics preservation is maximized on both the C_6/C_7 aromatics stream and C_8+ aromatics stream
- Aromatics net gain is maximized on the C_8+ aromatics stream
- Diolefins (which may shorten clay cycles[2]) are efficiently removed on both the C_6/C_7 aromatics stream and C_8+ aromatics stream.

This arrangement takes advantage of synergies such as desirable feed temperature and the use of the reformate stabilization column for removal of unreacted hydrogen and light ends, without any need for a flash drum or other stabilization means. Therefore, the low-cost, once-through process requires minimum equipment, namely a vessel and a heat exchanger. The impact on the stabilization column design is negligible because olefins to be hydrogenated rep-
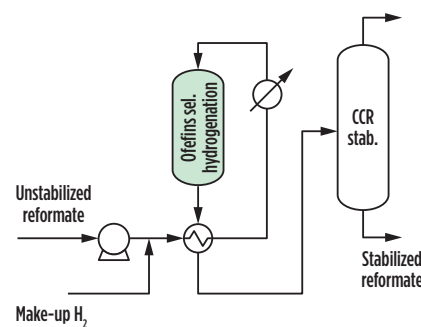
FIG. 1. Olefins selective hydrogenation unit inserted between the CCR and the reformate stabilization column.

resent a small fraction of the stream to be processed and the technology operates at low excess hydrogen. The source of make-up hydrogen is usually the catalytic reforming unit. The configuration is depicted in **FIG. 1.**

Heavy reformate stream: Incremental aromatic production doubled. Using selective hydrogenation rather than clay treating for olefins removal [or bromine index (BI) removal] from aromatic streams prevents the loss of valuable aromatics in the benzene/toluene and heavy reformate streams. However, as previously reported[1], the olefins to be removed in a heavy reformate stream are predominantly alkenyl aromatics. Plant sample analyses suggest that the prevalent molecules are methyl styrene, dimethyl styrene and styrene, accounting for most of the heavy reformate olefins content. **FIG. 2** illustrates how these molecules, when hydrogenated via selective hydrogenation rather than being converted to heavy aromatics by alkylation with aromatics of equivalent molecular weight in clay treaters, contribute to the overall complex aromatics production. Namely:

- Methyl styrene is converted to methyl ethylbenzene via selective hydrogenation. Then, in the transalkylation process, methyl ethylbenzene is dealkylated to produce a toluene molecule. Finally, still in the transalkylation process, toluene is transmethylated either with another toluene to yield a benzene and a xylene molecule, or with a trimethylbenzene to yield two xylene molecules (**FIG. 2A**).
- Dimethyl styrene is converted to dimethyl ethylbenzene via selective hydrogenation. Then, in the transalkylation process, dimethyl ethylbenzene is dealkylated to produce a xylene molecule (**FIG. 2B**).
- Styrene is converted to ethylbenzene via selective hydrogenation. If the complex operates an ethylbenzene-dealkylation isomerization, ethylbenzene is converted to benzene, while if the complex operates an ethylbenzene-reforming isomerization, ethylbenzene is converted to xylene (**FIG. 2C**).

Consequently, with olefins selective hydrogenation on the heavy reformate stream, not only is aromatics consumption for olefins removal avoided, but ole-fin-substituted aromatics are converted to additional valuable aromatics.

Process conditions, catalyst, selectivity and impact on C_6/C_7 and C_8+ aromatic streams. Since typical olefins content in reformate aromatic streams is in the order of 1%–2% by weight[3], the hydrogenation process is only useful if the olefins can be hydrogenated selectively, i.e., without simultaneous hydrogenation of aromatic compounds.[3,4] In the literature, palladium catalysts have been reported to be more selective than nickel catalysts.[4,5] In pyrolysis gasoline hydrogenation, palladium catalysts are usually preferred for the selective hydrogenation of styrene and diolefins, while nickel catalysts are preferred when some amount of aromatic saturation is targeted.[5] Further, conditions such as mild temperature and low excess hydrogen favor olefins hydrogenation while minimizing aromatic saturation, and also result in slower coke deposition, allowing longer cycles and softer coke (lower C/H ratio) formation that renders catalyst regeneration easier.

Diolefins selective hydrogenation, as well as the selective hydrogenation of the olefinic function of olefin-substituted aromatics, are achievable at milder conditions than the selective hydrogenation of aliphatic olefins, because the former molecules adsorb more strongly on catalysts' surface than the latter.[5,6] An olefins selective hydrogenation process positioned upstream from the reformate splitter must operate at mild conditions to avoid undesirable aromaticity loss. This drives BI removal efficiency differences on the C_6/C_7 and C_8+ aromatics streams, but these differences work to the advantage of the user due to the aromatics complex configuration:

- On the heavy reformate stream (C_8+ aromatics), where BI mostly results from the presence of alkenyl aromatics, the BI removal achieved by selective hydrogenation processing the full reformate stream is very high. Moreover, this stream is diluted downstream of the clay treater by the isomerate recycle C_8 aromatics stream containing very low BI, and—where a transalkylation unit is part of the process flow scheme—diluted by the transalkylate C_8+ aromatics stream, which also contains very low BI. Finally, any heavy olefinic species is removed from the xylene loop via the xylene splitter bottoms. All these conditions ensure that the BI feed specification to the paraxylene recovery unit is achieved for extremely long periods. Hence, the clay treater becomes a guard bed present for infrequent upsets or unusual feed contaminants; under normal conditions, the clay treater is expected to operate for many years without any need for clay change-out.
- On the light reformate stream, BI mostly results from the presence of aliphatic aromatics. BI removal achieved by selective hydrogenation processing the full reformate stream is substantially lower than on heavy reformate. However, light reformate is then processed in the extraction unit where additional BI is removed. The combined BI reduction by selective hydrogenation and aromatics extraction process yields a benzene/toluene extract stream with extremely low BI. Here as well, the clay treater becomes a guard bed essentially present for
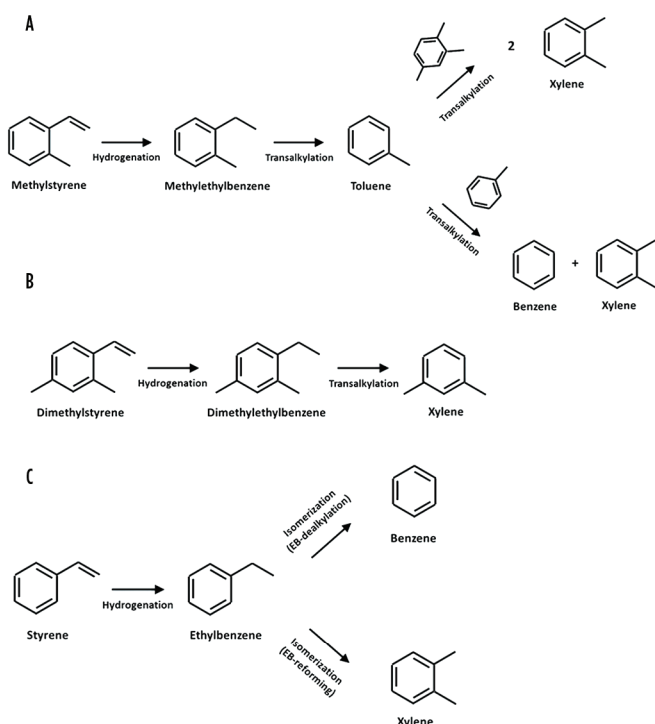
FIG. 2. Reaction pathways for the production of additional valuable aromatics produced by olefins selective hydrogenation.

infrequent upsets or unusual feed contaminants, and under normal conditions, the clay treater is expected to operate for many years without any need for clay change-out. In some plant designs, the clay treater has even been eliminated.

Commercial example: Selective olefins hydrogenation process in a CTC complex. **FIG. 3** depicts the aromatics block of a major CTC complex that has been producing paraxylene for 3 yr. Multiple continuous catalytic reformers produce aromatic-rich effluents, and each reformate stream is processed through an olefins selective hydrogenation unit prior to separation of light and heavy fractions in the reformate splitter. On the light reformate side, a BI reduction of > 60% is achieved. This stream is then fed to an extraction unit, where additional olefins are removed as raffinate. The raffinate from an aromatics extraction unit is a paraffinic cut that has low octane value, making it unattractive for disposition in the Mogas pool.[7]

Where a steam cracker is in operation, this raffinate provides much higher value as steam cracker feed, and the upstream olefins removal by selective hydrogenation makes it an even more suitable steam cracker feed. On the heavy reformate side, a BI reduction of > 90% is achieved. The heavy reformate stream is then combined with low-BI transalkylate and feeds multiple xylene loops for paraxylene recovery.

In typical clay treater operation on both C_6/C_7 and C_8+ aromatic streams, temperature is usually adjusted to maintain a BI removal (olefins conversion by alkylation) that meets the complex requirements for acid wash number (benzene/toluene extract) and paraxylene recovery unit specifications (heavy reformate). When the temperature reaches the maximum achievable by the clay treater, then spent clay is removed and replaced by fresh clay. While every complex is different, typical

FIG. 3. Schematic representation of the aromatics block of a commercial CTC complex.

FIG. 4. BI removal by a commercial selective olefins hydrogenation unit on a full reformate stream in the aromatics block of a CTC complex.
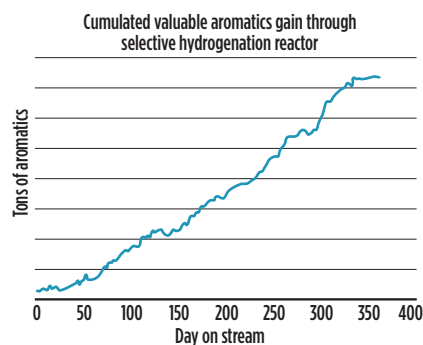
FIG. 5. Valuable aromatics gain by alkenyl aromatics hydrogenation through a selective olefins hydrogenation unit processing a full reformate stream.

clay treater cycles can range from a few weeks up to 12 mos in aromatic plants.[8,9] However, in this commercial CTC facility in service for 3 yr, clay has never been replaced in either C_6/C_7 or C_8+ aromatics service and the temperature has never been increased to compensate for loss of activity, meaning that both treaters are fed with streams containing extremely low BI levels. The clay in these treaters is expected to remain active for a long time.

FIG. 4 shows the stable operation as a function of time onstream of one of the selective olefins hydrogenation units in use at this facility. As can be seen, the site has decided to target 65%–70% olefins conversion to achieve (1) extremely low BI on the C_6–C_7 stream following additional olefins removal in the extraction unit, (2) extremely low BI on the C_8 aromatics stream via selective hydrogenation conversion combined with dilution effects explained above, (3) undetectable aromatic ring loss through the selective hydrogenation process, and (4) catalyst cycle exceeding complex turnaround requirements ($\geq$ 5 yr). The catalyst can then

be regenerated with very high activity recovery and reused for subsequent cycles.
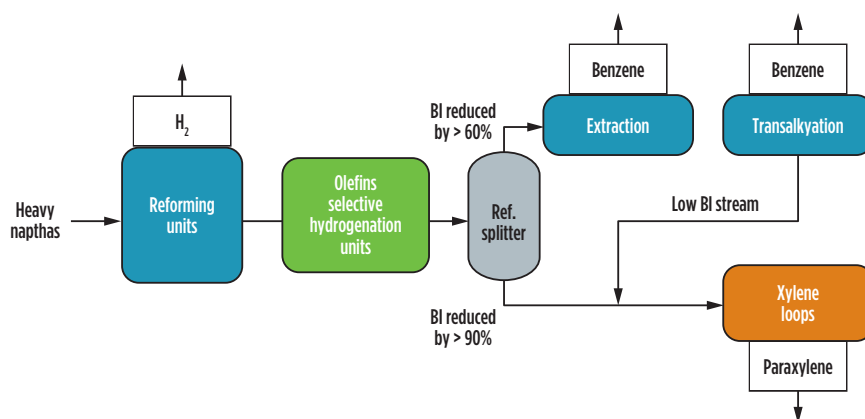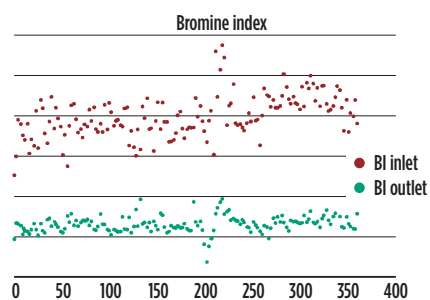
Assessing small incremental improvements can be challenging in a pilot plant and even more in a commercial environment. Data are usually scattered with a significant error bar, because small variations on large gas chromatography peaks are difficult to quantify[10] and also because such data are subject to flowmeter calibration variations. However, an attempt to measure valuable aromatic molecules gain in the plant through a selective olefins hydrogenation unit, as the result of the conversion of molecules such as styrene, methyl styrene and dimethyl styrene to alkyl substituted aromatics (as discussed earlier), is shown in **FIG. 5**. Time onstream monitoring suggests close to constant and consistent additional valuable aromatics generated via olefins selective hydrogenation throughout the year of data displayed in **FIG. 5**.

Selective olefins hydrogenation benefits in a CTC complex: Selectivity is key. The integration of a selective hydrogenation process on the full reformate of the aromatics block in a CTC complex offers massive benefits. For a 4-MMt paraxylene plant, additional production at constant feed rate exceeds 110,000 tpy when only taking into consideration the heavy reformate stream. This does not include the incremental benzene/toluene production on the light reformate stream, nor the incremental production obtained by avoiding frequent clay change-outs and associated start of cycle periods at high xylene losses.

For the commercial operation described in this article, it is estimated that 3 yr of operation without any clay change-out have already spared the purchase of about 7 MMkg of clay, as well as associated solid waste generation and disposal costs. This represents a massive environmental footprint reduction for this large aromatics facility.

Additional benefits include reduced traffic in the heavy aromatics column and associated energy consumption, as well as reduced solvent, energy consumption and benzene losses in the aromatics extraction process. Selective olefins hydrogenation is a must-have process for plants of CTC scale, and indeed all new CTC facilities coming onstream or under construction include a selective olefins hydrogenation process in their aromatics block flow dia-

gram. Yet the selection of catalytic technology and process operating conditions remains crucial: it is advisable to operate at slightly lower conversion where the catalyst nears 100% selectivity to avoid any loss of aromaticity, which could be fatal in streams with inherently high aromatics content. For the commercial operation described in this article, economic calculations have shown that 0.2% aromatics loss through hydrogenation would reduce by 60% the credits associated with the selective olefins hydrogenation process, while 0.5% aromatics loss would erase these credits almost entirely.

Takeaway. A selective olefins hydrogenation process with the appropriate selectivity has become an indispensable technology in the block flow diagram of very large aromatics complexes. Given the extent of aromatics losses and environmental footprint associated with clay treaters, selective olefins hydrogenation should also be considered by producers operating smaller aromatics facilities. **HP**

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Enhanced reboiler for C_3 splitter heat pump improves energy efficiency and reduces CO_2 footprint

Energy efficiency, carbon dioxide (CO_2) footprint reduction and the minimization of material requirements are becoming key drivers of our daily decisions in all industry sectors. With the example of a successful process integration of a propylene-propane splitter unit in an existing refinery and petrochemical plant environment, the authors would like to demonstrate the benchmark capabilities of a combination of sophisticated technologies for enhanced heat exchanger design, as well as distillation and vapor recompression technologies. The authors' focus is on a case study and the implementation of an enhanced thermosiphon reboiler/condenser heat exchanger for polymer-grade propylene production. Startup data from the field has proven the successful operation of this highly efficient unit.

This evaluation will focus on an open heat pump C_3 separation unit. The design concept of the enhanced thermosiphon reboiler, along with a cost evaluation of an economical and low-CO_2 footprint basis, will be presented. In the latter case, Scope 1–3 emissions[1] will be considered.

Background. According to the International Energy Agency (IEA), energy efficiency is "the first fuel of a sustainable global energy system."[2] Nevertheless, the agency noted that "global improvements in energy efficiency since 2015 have been declining." This is a reason for concern, as the IEA's Sustainable Development Scenario relies on an energy efficiency of 40% to ensure meeting international climate and energy goals in the next 20 yr. One of the causes of climate change is linked to the low cost of energy sources such as oil and gas. The COVID-19 pandemic has also strongly impacted recent investments in energy efficiency. While we have a good understanding of this global threat, and are increasing our control over it, the negative impact of climate change on our planet remains and proposing solutions that improve energy efficiency to reduce greenhouse gas emissions is the most economic means to reduce carbon intensity, according to the "Industrial Energy Transition Manifesto" of KBC, a Yokogawa Company.[3]

For more than 20 yr, in accordance with environment, social and governance policies, the co-authors' companies have jointly developed, and supplied to the energy industry, enhanced heat exchanger solutions that reduce unit size and improve energy efficiency. These solutions rely on dual enhanced tubes dedicated to the Tubular Exchanger Manufacturers Association (TEMA) type of shell-and-tube heat exchangers, especially for large heat duty services in the LNG and petrochemical sectors.

Borealis—one of the world's leading providers of advanced and circular polyolefin solutions and a European market leader in base chemicals and the mechanical recycling of plastics—has made energy efficiency a major axis of its strategic sustainability framework for energy and the climate.[4] It even goes further when energy efficiency is combined with the use of locally produced renewable electricity, as in its petrochemical facility in Porvoo, Finland, where energy efficiency actions are combined with a long-term power purchase agreement to supply the site with renewable energy.

This article will present the technical basis of a heat pump system applied to a distillation column that helps improve energy efficiency and minimize carbon footprint. The importance of the heat exchangers that are part of the heat pump system, the overhead condenser and the bottom reboiler will be presented. Technologies developed by the co-authors' companies will be described.
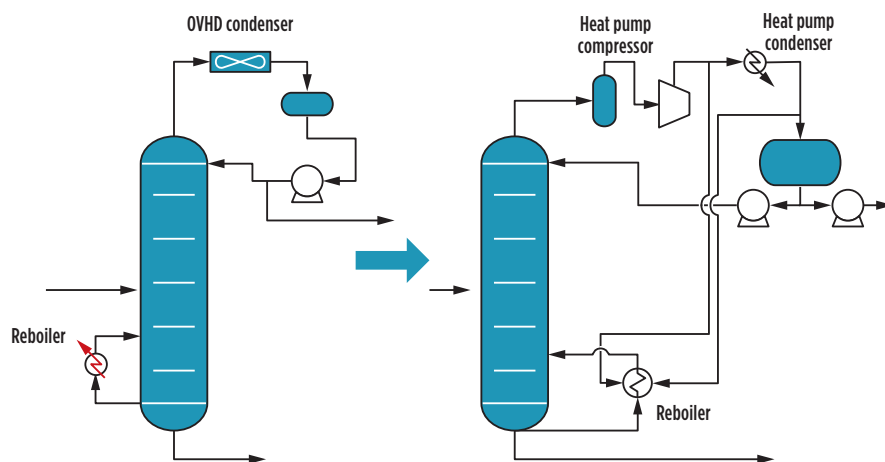

FIG. 1. Example of a heat pump implementation on a distillation column.

Lastly, the authors will demonstrate the successful implementation of a heat pump equipped with proprietary reboiler technologies for the upgrade of Borealis' C_3 splitter unit in Porvoo.

Heat pump principle. The heat pump principle in the frame of a distillation column (**FIG. 1**) targets the recovery of a part of the condensation duty released in the overhead condenser to be used for the boiling service at the bottom of the column.[5] The overhead vapor will be compressed at a pressure level allowing the overhead vapor to be condensed in the column reboiler. This requires products
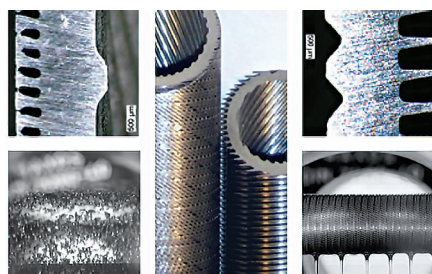
FIG. 2. View of two types of proprietary heat exchanger tubes: Enhanced boiling tubes[a] (left) and enhanced condensing tubes[b] (right).

FIG. 3. View of Borealis' petrochemicals plant in Porvoo, Finland. Photo courtesy of Borealis.

having close boiling temperatures (typically less than 45°C) and column bottom temperatures below 100°C. A prime example widely used in refining and petrochemical operations is the propane-propylene splitter column.

Energy savings are expected on a heating medium for the reboiler and in a reduction of the cooling water flowrate for the condenser. However, additional power is required to drive the compressor by using either an electric motor or a steam gas turbine. This additional power demand should be considered in the energy balance and carbon footprint.

The vapor compressor discharge pressure is directly linked to the reboiler boiling temperature, where the minimization of the temperature approach in the reboiler will allow for the minimization of the compressor work.

The major part of the gas overhead stream is routed to the reboiler. A trim condenser is required to condense the remaining vapor for reflux and other purposes.

Condenser and reboiler of a distillation column. If we focus on the heat exchangers associated with the distillation column, we must manage—on one side—the overhead condenser, which is generally water- or air-cooled, depending on the operating pressure of the distillation column. On the other side, the reboiler is generally heated by steam, but other sources can be used, such as a liquid heating medium (e.g., hot oil, quench water or hot process stream) or even electric heaters.

The most common exchanger type for these two services in the energy industry remains the shell-and-tube heat exchanger. Depending on the service, its orientation and fluid side allocation can differ. An overview of a typical condenser and reboiler arrangement is detailed in **TABLE 1.** The fouling propensity of each stream will play a key role in finalizing side allocation. Tube-side allocation for cooling water from the open loop is common to manage a minimum water velocity in tubes and to maintain a good shear rate to minimize fouling.

Depending on fouling and the associated cleaning requirement, the TEMA type of shell-and-tube heat exchanger will be defined. Horizontal NXN-type exchangers will perform well with a clean overhead vapor to be condensed, while horizontal AES-type exchangers will be recommended in the case of a fouling liquid boiling on the shell side heated by quench water, with both sides requiring mechanical cleaning.

The heat duties can be large in this service (several tens of MW are common), and several shells operating in parallel are usually required for the reboiler. Therefore, technologies that can improve the efficiency of the exchanger are of high value. Plain tubes can be replaced by externally finned tubes, which will help to increase the heat transfer area by a ratio of 2–3. Ultimately, dual enhanced tubes will provide the necessary heat transfer intensification, along with an increase in surface to maximize the heat transfer for both sides of the tube.

TABLE 1. Typical condenser and reboiler arrangement

Service	Hot fluid	Cold fluid	Installation	Process stream allocation	Remarks
Condenser	Overhead vapor	Cooling water	Horizontal	Shell side	–
Reboiler	Steam, hot oil, quench water or process stream	Bottom liquids	Horizontal	Shell side	Typically, hydrocarbon maximum vaporization rate of 50 wt%
Reboiler	Steam, hot oil, quench water or process stream	Bottom liquids	Vertical	Tube side	Typically, hy-drocarbon maximum vaporization rate of 35 wt%

Proprietary heat transfer solutions. For the past 20 yr, the co-authors' companies[c] have jointly developed technologies to serve the energy industry. These technologies primarily target the light hydrocarbon boiling and condensing services. Propane chilling trains on propane/mixed-refrigerant LNG trains or C_2/C_3 fractionations and splitting services and C_3 refrigeration units are good candidates to benefit from the proprietary enhanced nucleate boiling tube technology[a]. This technology[a] is a dual enhanced tube promoting nucleate boiling on the shell side, while inner microfin grooves increase surface area and promote turbulence, increasing the heat transfer on the tube side (**FIG. 2**). Typical fluids are light hydrocarbons such as ethylene, ethane, propane, propylene and butane.

Case study: C_3 splitter reboiler/condenser—Open heat pump loop. A C_3 splitter unit—more accurately referred to as a propylene/propane splitter unit—is used in the separation of propane and propylene. The difference in the molecular weights of propylene and propane is small (42.08 g/mol vs. 44.1 g/mol), as is the difference in their liquid-vapor equilibrium temperatures. For example, at 12 bara, the boiling point of propane is 34.3°C, while the boiling point of propylene is 26.2°C. The difference of 8.1°C is well below 45°C, and the boiling points are also lower than 100°C. The fractionation column of such a unit will receive a feed stream where the two molecules are mixed with potential traces of heavies. The propylene will be separated from the propane and will exit in the gas phase at the top of the column, while the propane-concentrated liquid stream will leave at the bottom of the column. A reboiler will partially vaporize the stream, starting the propylene/propane separation and heating the column. Because of the very close volatility of the two components, the separation is difficult and will require many trays in the column and even several columns in series.

The propylene gas phase will generally be condensed with cooling water, and a part of the condensate will come back to the column as reflux stream. The main part of condensate will leave the unit as propylene product. The heat available in the vapor is lost to the environment. By directing the vapor to the reboiler, some heat can be saved. Nevertheless, the temperature level of the exhausting vapor is too low to ensure the heat transfer in the reboiler. It is necessary to increase the pressure of the pure propylene stream to increase its dewpoint.

Application of a heat pump to Borealis' C_3 splitter unit at its Porvoo facility. As presented at *Hydrocarbon Processing's* International Refining and Petrochemical Conference (IRPC) EurAsia in June 2019 in Helsinki, Finland, Borealis evaluated several process schemes to upgrade the C_3 splitter unit for additional propylene production capacity at the Porvoo facility (**FIG. 3**), along with changing from chemical grade propylene (98 wt%) to polymer grade (99.5 wt%). The upgrade had to be performed within a given setup and within a limited plot space. As the reboiler and condenser duties will increase signifi-

cantly, and given the shortage of quench water (already supported with steam in the existing unit) and cooling water (the cold source for the condenser) during the summer season, Borealis selected a vapor recompression heat pump scheme. The former unit was composed of three C_3 splitter columns operating in series to produce a chemical grade propylene product (**FIG. 4**).

The middle and bottom columns were equipped with quench water reboilers, and the middle and top columns were equipped with cooling water condensers. The middle column is larger than the other two. As mentioned, steam heating of quench water was needed to supply sufficient energy to users and to operate the reboilers.

The vapor compression heat pump had several advantages. A revamp of the existing reflux system was not needed when the heat pump system was designed to provide enough reflux. The existing condenser on the middle column was kept as the trim condenser in the case of the condensing load being higher than the duty released in the new reboiler/condenser reboiler. The existing reboiler in the middle column required no modification, as the required additional duty is phased in through a new reboiler/condenser within the vapor recompression cycle. This scheme minimized the number of new equipment items. Furthermore, the system was able to operate without the heat pump at reduced capacity. For example, this case could occur during maintenance activities on the compressor.

The first drawback was that the new reboiler/condenser had to be located close to the middle column to allow the reboiling side to operate in thermosiphon mode. Some space was required by the heat pump housing (**FIG. 5**), and it was also necessary to power the compressor.

Several design options were considered when finalizing this system. The compressor head was defined to be high enough to provide reflux to the middle column. The heat pump compressor was selected to be an electric motor driven with inlet guided vanes (IGVs). In addition, the compressor design was selected to be as simple as possible. Because of cooling water temperature variation, the system was designed to work with column operating pressures ranging between 12 bara–16 bara.

The new heat pump was commissioned in 2017, with very good results. The targeted product propylene quality (99.5 wt%) and capacity were exceeded. This success was due to a good distillation tray selection and performance, heat pump design and performance, and advanced process control. Part of the heat pump performance is due to the new reboiler/condenser heat exchanger using the proprietary enhanced nucleate boiling tube technology[a].

Challenges of designing a reboiler/condenser. When installing new equipment in an existing facility, compactness is always advantageous. The selection of high-efficiency tubes minimizes the plot space requirements.

A second challenge is the piping, especially for this exchanger, as the reboiler operates in thermosiphon mode. Installation close to the column, along with well-designed piping, secure the level of performance.

Design duty is 37 MW, with a turndown of 10 MW. The logarithmic mean temperature difference (LMTD) is set to 10°C as a compromise between energy savings, compressor load and exchanger size. Using a proprietary dual enhanced tube[a] allowed a single shell design to be used with the associated inlet and return piping to the column under a confined space (**FIG. 6**). As the vapor fraction on the boiling side was set to 30 wt%, a horizontal X TEMA-type exchanger was developed
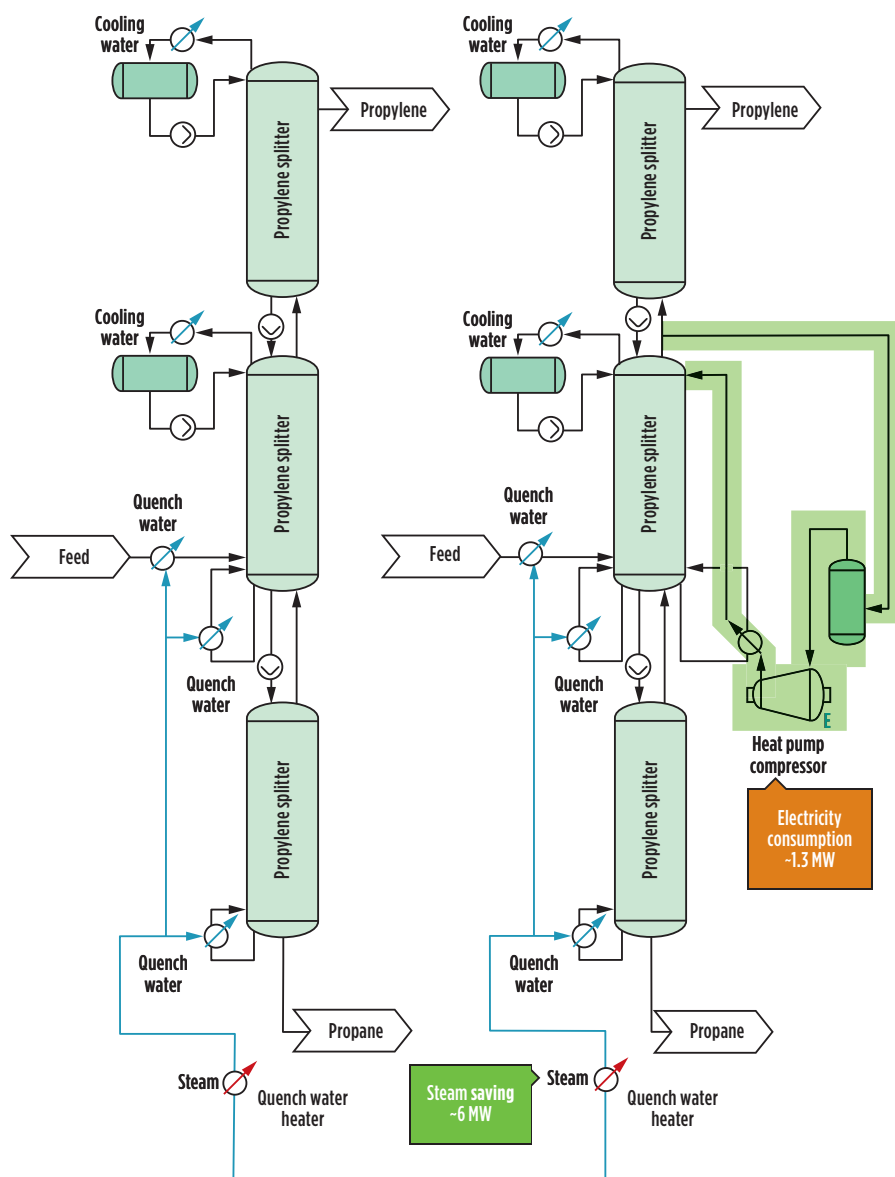

FIG. 4. Former C_3 splitter unit (left) and the upgraded C_3 splitter unit with a vapor recovery heat pump system (right).

by the co-authors' companies (**FIG. 7**).

When in operation, the heat pump system was reported to show savings in steam production of about 6 MW. This satisfied the goal of minimizing the heating of quench water and to avoid any investment in additional steam usage. Regarding cooling water, no extra capacity was required—thus saving some investment. In the balance, the compressor required about 1.3 MW of electricity.

Shifting energy input from steam to electricity helps in sourcing energy from renewable sources. Borealis will purchase more than 20 MW of wind power over the next decade, enabling a 13% increase in renewable power in its overall electricity consumption at its production facilities in Porvoo.

What would have been the final scheme without the co-authors' companies technology?
The following will provide a comparison between standard tubes and the proprietary enhanced nucleate boiling tubes[a].

Usually, approved technology for this service is standard low-finned tube technology. This technology requires an increase of the heat transfer area of the tube, typically by a factor of 2–3 vs. a plain tube. If this technology is considered vs. plain tube technology, it is not necessarily better for this application for the following reasons:

- The shell-side heat transfer coefficient is controlled by the heat flux (i.e., the difference of temperature between the cold and the hot stream). The enhanced nucleate boiling tube[a] was specially developed for light hydrocarbon nucleate boiling to generate bubbles at very small temperature superheat, with minimal heat flux. The resulting heat transfer coefficient is 2× higher than the one for a low-finned tube under the conditions of this case.
- The tube-side heat transfer coefficient is the governing coefficient for this application. The enhanced nucleate boiling tube[a] proposes an inner groove that increases turbulences to help disrupt the liquid film at the wall, making the area available for new vapor to be condensed. It also provides an additional heat transfer

area compared to the smooth internal surface of a low-finned tube.

Because the enhanced nucleate boiling tube technology is more efficient, a design based on low-finned tubes cannot meet the same targets, making it necessary to increase the size of the equipment. **TABLE 2** details two design scenarios compared to the installed one. Scenario 1 (iso duty) is a design based on 30 fins per inch (fpi) low-finned tubes, maintaining the same LMTD compared to the actual design. Scenario 2 (iso size) maintains the actual size, replacing each enhanced nucleate boiling tube[a] by a 30-fpi low-finned tube and a larger LMTD. For Scenario 2, the lower heat duty must be compensated by the increase of condensing vapor pressure by +1.8 bar, resulting in a larger compression power.

Scenario 1 (iso duty): Larger size means larger CO_2 footprint.
In the first case (low-finned design meeting the same heat duty), a 75% increase in tube length is required with the low-fin technology to perform the same duty. As the original solution weight is already heavy (60 t), it was mandatory to add a second shell. For some cases with multiple shell designs, the co-authors' companies' solutions can help reduce the number of shells, saving on capital expenditures and meeting space limitations.

For the low fin design, the authors calculated a total dry weight that was 87% higher than the actual design. As these exchangers are made of steel, the manufacturing weight is directly related to the carbon emissions during the manufacturing. The publicly available French database managed by ADEME—the French Agency for Ecological Transition—gathers several pieces of information about

FIG. 5. New compressor housing. Photo courtesy of Borealis.

carbon emissions. ADEME differentiates between recycled and new carbon steel. The CO_2 emissions by 1 t of steel ranges from 0.938 (recycled steel) to 2.211 (new steel) t of CO_2 equivalent emitted, depending on the final mix of steel sources. In this case, the enhanced nucleate boiling tube[a] solution saves 87% of CO_2 emissions. The impact of tube technology—the enhanced nucleate boiling tube[a] vs. a low-finned tube—and the origin of steel on CO_2 emissions are shown in **FIG. 8.**

Besides capital expenditure savings and minimizing CO_2 footprint, additional savings in installation costs should also be considered. A larger number of shells results in more piping (for the distribution of vapor from the compressor and condensate reflux to the column), structures and foundation concrete. In addition, for thermosiphon-based heat exchanger units with multiple shells, particular care in designing the cold-side piping to and from the column must be taken to ensure good fluid balance between the shells operating in parallel. This case also assumes that the required space for multiple shells would have been available around the column.

Scenario 2 (iso size): Energy efficiency supports carbon footprint reduction.
The second case maintains the existing space, replacing each enhanced nucleate boiling tube[a] solution with a 30-fpi low-finned tube. As the efficiency of the low-finned tube is lower, to reach the
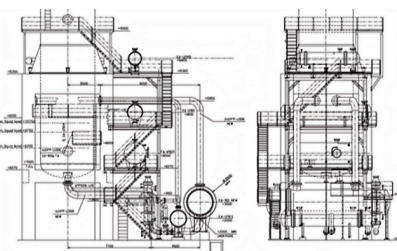

FIG. 6. Reboiler/condenser installation at the bottom of the column. Photo courtesy of Borealis.

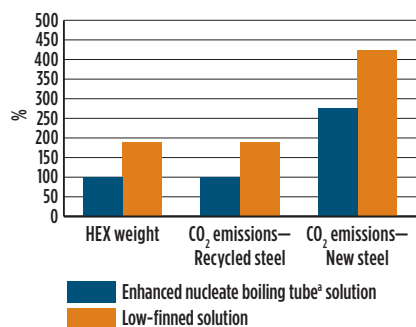
FIG. 7. Heat exchanger leaving the factory in Austria.

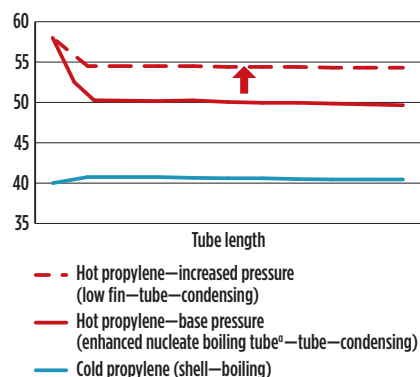**FIG. 8.** CO_2 equivalent emissions on mass of steel and steel mix.

FIG. 9. Cold and hot stream temperatures in the reboiler/condenser equipped with the enhanced nucleate boiling tube[a] (reference) vs. low-finned tubes (increased pressure).

TABLE 2. Technology impact on reboiler/condenser efficiency and size

	Installed design: Enhanced nucleate boiling tube[a]	Scenario 1: Low-finned tube (iso duty)	Scenario 2: Low-finned tube (iso size)
Heat duty, %	100	100	76
No. of shells	1	2	1
Bare tube area, %	100	175	100
Total dry weight, %	100	187	100
Required vapor pressure increase	N/A	N/A	+1.80 bar

Notes: Basis of 100% corresponds to the values of the enhanced nucleate boiling tubes design[a]; low-finned evaluation is based on a 30-fpi carbon steel low-finned tube geometry; dry weights are calculated using HTRI Xist® section of Xchanger Suite® software version 8.2.

TABLE 3. Carbon footprint comparison vs. electricity production score

Electricity production source	Nuclear	Gas	Coal	Wind (onshore)
Carbon emission, $kgCO_2eq/kWh$	0.006	0.418	1.058	0.0141
Extra CO_2 emissions, tCO_2eq	18	1,228	3,107	41
Earth rounds by car	3	181	459	6

same level of heat duty, the condensing vapor temperature must be raised by increasing the pressure. **TABLE 2** shows a 24% loss of duty due to the use of a low-finned tube. This can be compensated by increasing the pressure by 1.8 bar, corresponding to an increase of tube-side hot propylene condensing temperature of 3.9°C (**FIG. 9**).

The pressure increase linked to the use of the low-finned tube is proportional to the electric consumption of the compressor that must be provided, with approximately 26% more electric power required at the compressor shaft (0.34 MWel).

The compressor is electric motor driven. The extra carbon emissions of this additional power when using a low-finned tube instead of the enhanced nucleate boiling tube[a] will depend on the fuel mix used to supply the electricity. For various fuel sources and their specific characteristics, the extra CO_2 emissions are calculated in **TABLE 3,** assuming year-round operation (8,640 hr). To make this increase of CO_2 emissions easier to understand, the authors converted these values into kilometers driven by a car. Converted into Earth rounds, assuming a diesel car with average emissions of 169 gCO_2eq/km (as per the ADEME database), this would range from 3–459 times around the Earth. A significant contributor to reduce CO_2 emissions in the future is the use of renewable energy sources.

Takeaway. As the world faces significant environmental challenges, energy-efficiency solutions are necessary to meet reductions in carbon footprint. The co-authors' companies have worked for more than 20 yr to develop such solutions for the energy industry. By choosing these solutions and engaging in several initiatives, Borealis intends to be a leader in energy efficiency.

The co-authors' companies' dual enhanced tube solutions have demonstrated their beneficial impacts vs. low-finned tubes, resulting in savings on the number of shells that must be installed and on capital expenditures. The technology also preserves natural resources, resulting in lower CO_2 emissions during manufacturing, transportation and installation. The enhanced nucleate boiling tube[a] technology has been proven to be successful in supporting the introduction of more efficient process schemes with heat pumps, thus lowering power consumption and reducing carbon footprints. Additionally, it fosters the shift from fossil fuels to electricity, further promoting the use of renewable energy sources in proposed solutions.

Through the installation of a vapor recompression heat pump system in its Porvoo facility, Borealis and the co-authors' companies—combining market and carbon footprint objectives—have demonstrated strong capabilities to design, install and operate reliable, mature and sustainable solutions. HP

NOTES
[a] Wieland GEWA-PB enhanced nucleate boiling tubes
[b] Wieland GEWA-KS dual enhanced condensing tube
[c] Technip Energies and Wieland Thermal Solutions: https://www.wieland-thermalsolutions.com/en/industries/process-technology/cooperation-technip-wieland

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New practice of diameter-transformed fluidized bed reactor in the petrochemical industry

Motor gasoline standards are becoming increasingly stringent—in particular, the olefins content requirement in motor gasoline is getting lower and lower. Among these standards, China standard motor gasoline VI (B) requires that the olefin content should be < 15 vol%. However, the olefin in China's gasoline pool is mainly from fluidized catalytic cracking (FCC) gasoline. Therefore, the production of low-olefin gasoline is a vital issue in the development of FCC technology.

With the rapid development of the olefin industry, a strong demand exists for chemical raw materials like ethylene and propylene. Increasing the production of propylene has become one of the important tasks of an FCCU. Based on research on the catalytic reaction pathway and the mechanisms of petroleum hydrocarbon molecules, the authors' company proposed the concept of a fluidized bed with a transformed diameter to construct different reaction zones,[1–8] and invented a novel diameter-transformed fluidized bed (DTFB) reactor.[9–11]

Based on this novel reactor platform, a series of technologies have been successfully developed: maximizing iso-paraffins in cracked naphtha (MIP),[12,13] cleaner gasoline and more propylene (CGP),[14,15] LCO to gasoline (LTG),[16,17] and integrated technology of hydrotreating FCC gasoil and highly selective catalytic cracking for maximizing liquid yield (IHCC),[18,19] which have achieved large-scale applications. These technologies play an important role in clean fuels production, product structure adjustment and refining technology upgrading that produce good social and economic benefits.

DTFB reactors have been applied to more than 100 industrial catalytic cracking units[20] by a patent licensed mode with an annual processing capacity of more than 120 MMtpy. DTFB reactors have been developed into an open engineering technology platform—recently, the catalytic cracking technologies for the production of ultra-low olefin gasoline and for more propylene and marine fuel oil components have been developed on this platform. These new technologies have injected new vitality into the development of catalytic cracking technology.

What is a DTFB? A DTFB reactor, shown in **FIG. 1,** is a multi-flow, single-vessel fluidized bed that is organically composed of a transport bed, a fast fluidized bed and a turbulent fluidized bed. It mainly includes the first reaction zone (transport bed), the second reaction zone (turbulent fluidized bed and fast fluidized bed), the outlet zone (transport bed), transition zone, gas-solid fluidized distributor and spent catalyst circulating pipe (not

shown). A DTFB reactor can not only achieve a low-temperature (with injection of quench medium or spent catalyst) or high-temperature (with injection of semi-regenerated catalyst or regenerated catalyst) environment in the second reaction zone, but also provides enough time, sufficient space and an abundant amount of catalyst particles. These favorable conditions can promote gasoline olefin molecules to undergo secondary reactions, such as isomerization, selective hydrogen transfer and re-cracking.

Quite different from the conventional riser, a DTFB has the characteristics of a multi-flow type and multi-temperature zone that can meet the different requirements of different chemical pathways of reactants in kinetics and thermodynamics. A DTFB realizes a new riser temperature distribution, a new catalyst concentration distribution and a new oil and gas velocity distribution.

A DTFB's reaction mode design. From the viewpoint of FCC reaction chemistry, hydride transfer reaction plays a key role as it is not only the elementary reaction of bimolecular cracking reaction, but also the elementary reaction of the hydrogen transfer reaction. In the presence of solid acid catalyst, carbenium R_2^+ will extract hydride ions from the raw material molecules (e.g., alkanes) to undergo a hydride transfer reaction, which converts itself into product alkanes (R_2H) and makes the raw material molecules form a new R_1^+. After that, the entire catalytic cracking reaction continues.

Based on the hydride transfer reaction, the bimolecular reaction evolves into an increasingly complex reaction system as the reaction depth increases. The optimization of the reaction depth and the control of the reaction direction are the fundamentals for achieving directional control of product distribution.
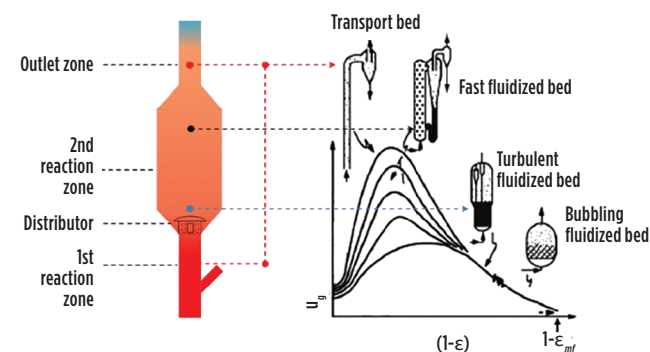

FIG. 1. The DTFB and its reaction zone with corresponding flow pattern.

Among them, hydrogen transfer reaction is divided into two types, as shown in **FIG. 2,** and the involved chemical bond evolution includes double bond saturation, aromatization, isomerization, disproportination, etc. Therefore, further deep hydrogen transfer will form coke precursors. The conversion rate is an indicator of the depth of the reaction, and the direction of the reaction is to regulate the type of hydrogen transfer reaction, and then directionally regulate the product distribution and gasoline composition. Based on these studies, the mechanism and method for the selective regulation of the bimolecular reaction and the optimization of the reaction depth by the hydride transfer reaction were discovered.

If the hydrogen transfer Type I is enhanced, gasoline olefins are converted into iso-paraffins and aromatics, which are benefi-

Hydrogen transfer Type I

$$3C_nH_{2n} + C_mH_{2m} \longrightarrow 3C_nH_{2n+2} + C_mH_{2m-6}$$

Hydrogen transfer Type II

$$C_nH_{2n-2} + C_mH_{2m-6} \xrightarrow[\text{Condensation}]{\text{HT}} \text{Fused Ring Aromatics} \longrightarrow \text{Coke precursors} \longrightarrow$$

$$C_nH_{2n} \xrightarrow{\text{H}^- \text{ Transfer}} C_nH_{2n+2}$$
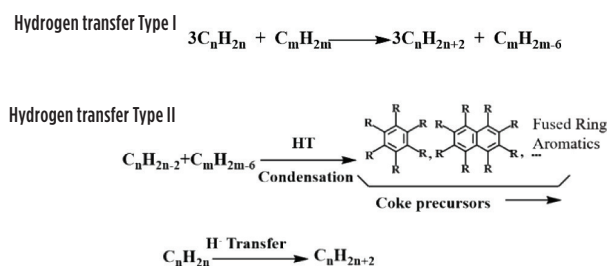
FIG. 2. Two types of hydrogen transfer reaction.
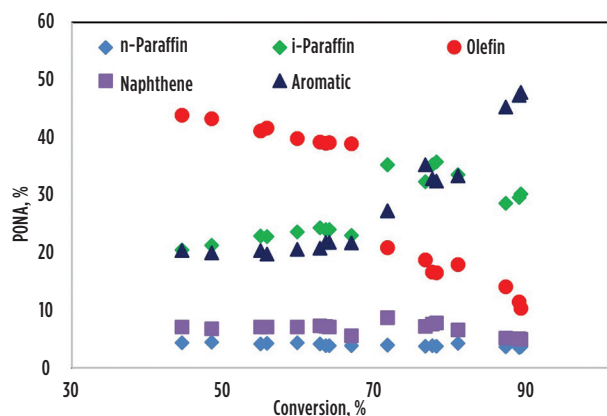
FIG. 3. The relationship between gasoline composition and conversion.
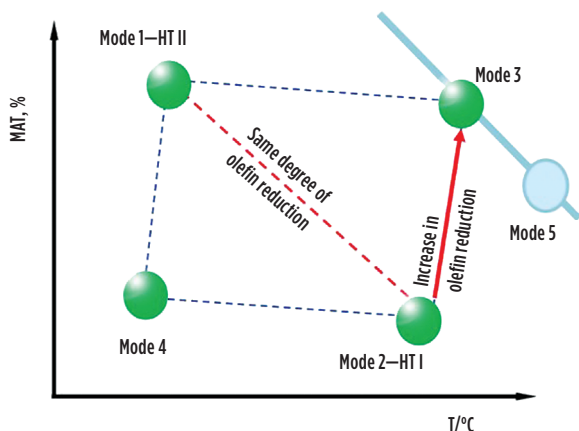
FIG. 4. Diagram of the DTFB's reaction mode.

cial to increase gasoline octane number. If hydrogen transfer Type II is enhanced, gasoline olefins are converted into iso-paraffins with different carbon numbers, but the yield of coke precursors is also increased. Also, excessive intensification of hydrogen transfer Type II can easily lead to a substantial increase in the yield of coke. The relationship between conversion (reaction depth) and gasoline composition (reaction direction) is shown in **FIG. 3.**

Conversion rate has a great influence on the composition and octane number of gasoline and is defined as the mass fraction of coke, cracked gas and gasoline. **FIG. 3** shows PONA data of gasoline at different conversion rates. When the conversion rate is < 65%, the gasoline olefin content slowly decreases as the conversion rate increases, the iso-paraffin content slowly increases, while aromatic content remains almost unchanged. When the conversion rate is between 65% and 80%, the olefin content decreases rapidly, and both iso-paraffins and aromatics increase significantly. When the conversion rate further increases, the olefin content continues to decrease but the extent slows down. Therefore, to further reduce gasoline olefins in an FCC process, increasing the conversion rate is the main direction for the adjustment of the reaction mode.

By means of DTFB reaction engineering technology and the structural optimization of molecular sieve catalysts, big data analyses of all factors affecting conversion rate and transfer reaction type are carried out—it is found that the reaction temperature and catalyst activity are the most significant. The reaction mode between catalyst activity and reaction temperature is established and a relationship diagram is shown in **FIG. 4.**

Based on the reaction mode constructed in **FIG. 4,** the conversion rate can be adjusted, while the type of hydrogen transfer reaction can be adjusted—then, the gasoline composition can be directionally adjusted. From the selective transfer reaction mode (Mode 2), the reaction temperature and catalyst activity are further optimized to construct a high-severity reaction mode (Mode 3 or mode 5), which will increase the conversion rate and reduce the olefin content of gasoline. Tests have shown that the olefin content of gasoline in Mode 3 can be reduced to less than 15%, and the content of iso-paraffins has increased significantly. Based on the regulation of bimolecular hydrogen transfer reaction, the concept and method of selective hydrogen transfer were developed—that is, hydrogen transfer Type I should be carried out as much as possible to reduce coke formation. This has laid a solid foundation for the development of corresponding processes and catalysts.

However, as the olefin content of gasoline is greatly reduced, the coke yield is greatly increased (**FIG. 5**), making it difficult to operate smoothly in Mode 3 and presenting challenges to the normal operation of the FCCU. The main reason for the substantial increase in coke yield is that the fused ring aromatics and olefins continue to undergo hydrogen transfer reaction Type II, and the condensation reaction produces coke. Therefore, the contradiction between the deep reduction of olefins and the rapid increase in coke yield is a scientific problem to be resolved.

DTFB to produce ultra-low olefins gasoline: The discovery of hydride ion release agent and its catalytic conversion path. Based on the test result that the selectivity of 2-methyl-2-butene's hydrogen transfer reaction on different spent catalysts is less than 20%, to further reduce gasoline olefins, it was

proposed to find a kind of hydride ion release agent to strengthen the hydride ion transfer reaction. A large number of experimental verifications have shown that tetralin and decalin are potential hydride ion release agents, which can promote 70% of 2-methyl-2-butene to undergo hydrogen transfer to form isopentane. At the same time, tetralin and decalin are converted to naphthalenes, and the coke yield of the reaction decreases instead.

Then, the catalytic reaction test of a mixture of olefin-rich gasoline and tetralin was conducted. As the concentration of tetralin molecules in the olefin-rich gasoline increases, the yields of dry gas and coke show a significant decrease. Meanwhile, the content of olefins gradually decreases—at its lowest, reaching 4%—and the content of paraffins and aromatics increases. This shows that the reaction between olefins and tetralin molecules is mainly hydrogen transfer reaction Type I, which produces paraffins and aromatics, rather than hydrogen transfer reaction Type II, which produces coke precursors. The role of tetralin in the reaction process with olefins and its catalytic conversion path was determined. Only a small part of tetralin undergoes β-scission reaction (**FIG. 6**), while most of them form aromatic hydrocarbons through hydride ion transfer reaction and proton removal reaction (**FIG. 7**). In this process, tetralin replaces the polycyclic aromatic hydrocarbons (PAHs) in the original system to release hydride ions, thereby inhibiting the condensation of PAHs to form coke without causing a rapid increase in coke yield. At the same time, it can significantly promote the hydrogen transfer reaction of olefin molecules to generate paraffins.

Development of catalytic cracking technology for ultra-low olefin gasoline. A methodology and mixing ratio of a hydride ion release agent into the reaction system are proposed here. The most typical compounds of hydride ion release agents are tetralins and decalins. FCC light-cycle oil (LCO) contains many naphthalene compounds. After hydrotreating, naphthalene compounds become tetralins and decalins. In other words, these compounds can be derived from hydrotreated FCC LCO.

The hydride ion release agent is similar to a working fluid, which circulates between the catalytic cracking unit and hydrotreating unit to release hydrogen or hydrogenate. The reasonable way to introduce the hydride ion release agent to the fresh heavy oil reaction system is to directly mix the hydrogenated LCO with fresh heavy oil and then introduce the mixture into the riser reactor. This can significantly improve the physical properties and chemical reaction performance of the heavy oil.

The mixing ratio of hydrogenated LCO and fresh heavy oil was systematically studied. It was found that when the mixing ratio of hydrogenated LCO exceeds 10%, the viscosity of the heavy oil can be significantly reduced, which can reduce the dry gas and coke yield in the catalytic cracking process of heavy oil feedstock. In this process, the hydrogenated LCO itself is a high-quality heavy oil emulsifier. As a result, a catalytic cracking technology [ultra-low olefins (ULO)] for the production of ultra-low olefin gasoline was developed. Industrial operating data of ULO technology are shown in **TABLE 1.**

With the introduction of an external hydride ion release agent, the contradiction between the deep reduction of gasoline olefins and the rapid increase in coke yield has been fundamentally resolved. As shown in **TABLE 1,** with the introduction of a hydride ion release agent (mixing ratio of 12%) into fresh heavy oil, gasoline olefin content decreased to 8.5%. When the conversion rate
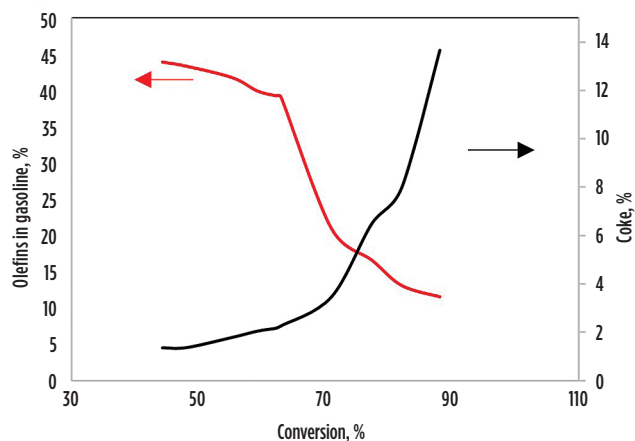
FIG. 5. Variation curve of gasoline olefin content and coke yield with conversion rate.
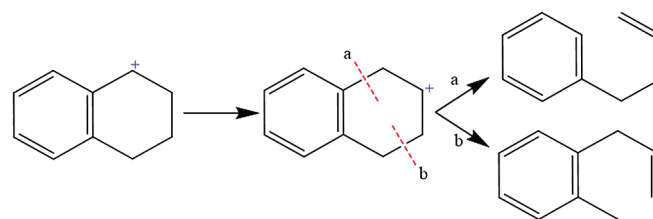
FIG. 6. The β-scission is difficult for a hydride ion release agent.
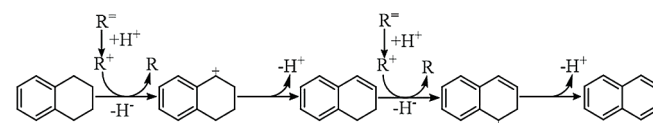
FIG. 7. Schematic diagram of hydride ion release agent promoting olefin saturation.

TABLE 1. Industrial operating data before and after ULO application

Technology	MIP	ULO
Feedstock properties		
Density (20°C)/(kg·m^{-3})	926.7	914.5
CCR, %	3.21	3.01
Product distribution, %		
Dry gas	3.01	3.38
LPG	12.03	23.27
Gasoline	46.24	43.09
Diesel	25.56	16.62
Slurry	3.84	4.55
Coke	8.96	9
Gasoline properties		
Olefins, %	24.8	8.5
Aromatics, %	25.5	29.6
RON	91.6	92.7

increased from 70.6% to 78.8%, the coke yield increased slightly.

Compared with advanced catalytic cracking technology (MIP), the gasoline composition of the ULO technology is quite different (**FIG. 8**). MIP gasoline has high isoparaffin content and moderate olefin and aromatic content, the result of both the cracking reaction and hydrogen transfer reaction. ULO gasoline has much higher isoparaffin content, with an olefin content less than 10%, and slightly higher aromatics content, the result of strengthening the selective hydrogen transfer reaction.

TABLE 2. DTFBs use different heavy oil to produce propylene and marine fuel oil

Feedstock	HVGO	VRDS	AR
Density (20°C)/(kg·m⁻³)	892	921	925
Hydrogen content, %	12.85	12.19	12.3
Reaction temperature, °C	530	530	530
Product distribution, %			
Dry gas	2.25	4.09	4.36
LPG	27.47	26.37	23.18
Gasoline	32.49	26.17	25.61
Light diesel	7.03	5.89	4.45
Marine fuel oil	28.77	31.13	36.44
Coke	1.99	6.36	5.96
Total	100	100	100
Propylene, %	11.61	10.67	10.03
Total butene, %	11.21	10.82	9.54

TABLE 3. Overview of three sets of DTFBs for processing hydrogenated heavy oil

Company	HN	JL	SH
Capacity, Mtpy	280	350	350
Feedstock			
Density (20°C)/(kg·m⁻³)	929	916	926
CCR, %	5.33	4	5.2
w(S), %	0.4	0.39	0.4
w(Ni)/(µg·g⁻¹)	7	10.9	4.2
w(V)/(µg·g⁻¹)	4.5	5.3	6.5
Product distribution, %			
Dry gas	3.39	2.85	3.11
LPG	21.65	19.07	13.42
Gasoline	39.97	43.02	46.89
Diesel	20.69	21.55	21.54
Slurry	5.22	5.3	6.7
Coke	8.89	8.06	7.84
Gasoline properties			
v(olefins), %	22.92	23.86	23.2
v(aromatics), %	27.1	26.73	29.3
RON	94	94.1	91.8
MON	82.5	82.3	80.3
w(S)/(µg·g⁻¹)	145	220	84.3
STC, %	3.63	5.64	2.11

Producing more propylene and marine fuel oil components. With the progress of the times, the products produced by DTFB can be transformed from conventional gasoline and diesel to light olefins and marine fuel oil, which means a DTFB continues to play an important role in the petrochemical industry. By using three different types of heavy oil, a DTFB produces more propylene and marine fuel oil components. The test results are listed in **TABLE 2.**

From **TABLE 2,** with hydrogenated vacuum gasoil (HVGO), vacuum residuum desulfurization (VRDS) or atmospheric resid (AR), a DTFB can directly produce propylene with a yield of > 10% and a marine fuel oil component yield of > 28%. If the operation mode of light gasoline or light diesel recycling is adopted, the propylene yield will be higher. Therefore, a DTFB has achieved another transformation and upgrading.

Advances in processing hydrogenated heavy oil. In recent years, the trend of heavy and inferior crude oil has become prominent, and the price gap between high-sulfur crude oil and low-sulfur crude oil has widened. To improve the utilization efficiency of petroleum resources and increase economic benefits, refiners are favoring the combined processing route of the residual oil hydrogenation unit and the catalytic cracking unit. Compared with straight-run residue oil, the product distribution of catalytic cracking of hydrogenated heavy oil has been significantly improved, and product properties—especially the olefin and sulfur content of gasoline—have been greatly improved.

TABLE 3 lists the overview of three sets of DTFBs for processing hydrogenated heavy oil, including the main properties of raw materials, product distribution and gasoline properties during

FIG. 8. Comparison of gasoline olefin (left) and isoparaffin distribution (right) of ULO and MIP.

FIG. 9. Changes in gasoline properties before revamp and after revamp to the DTFB.

calibration. For hydrogenated heavy oil, the product advantages of a DTFB reactor are low olefin content in gasoline and high RON. Additionally, with special catalysts and a flexible switch of the reactor operation mode, it can produce more propylene.
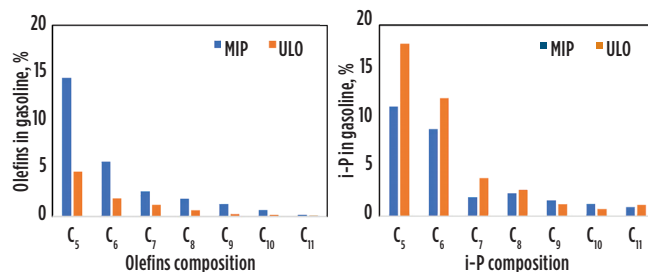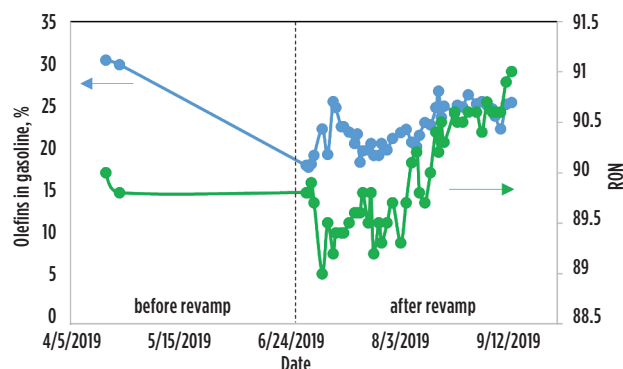
Advances in processing paraffin-base heavy oil.
With the development of special catalysts and new DTFB engineering technology, the adaptability of a DTFB in processing paraffin-base heavy oil has been greatly improved. For a clean gasoline production program, compared with an early DTFB, the olefin content of gasoline can be reduced from 35% to less than 20%, while RON increases.

Using a petrochemical company that is processing paraffin-base heavy oil as an example, the changes in gasoline properties before revamp (adopting a conventional riser) and after revamp (adopting a DTFB) are shown in **FIG. 9.** It can be clearly seen that the olefin content of gasoline produced is ~30% and RON is ~90 when the conventional riser is used and the equilibrium catalyst activity is 70 (the unit consumption of fresh catalyst is 1.6 kg/t of heavy oil). After revamp into the DTFB, the olefin content of gasoline can be reduced to < 20%, the olefin content of the gasoline is 23%–25% and RON is 90.5–91.1 after the operation mode adjustment.

At this time, the unit consumption of fresh catalyst is only 0.5 kg/t of heavy oil. This is because the second reaction zone of the DTFB has the characteristics of high catalyst density and long reaction time, which strengthen the hydride ion transfer reaction. From the reaction mechanism, the hydride ion transfer reaction is the elementary reaction of the hydrogen transfer reaction and the bimolecular cracking reaction. Therefore, strengthening the hydride ion transfer reaction will inevitably increase the hydrogen transfer reaction and the bimolecular cracking reaction rate simultaneously. This strengthens the conversion of small molecular olefins into isoparaffins; on the other hand, it strengthens the bimolecular cracking reaction between small molecular olefins in gasoline and large molecular saturated hydrocarbons in diesel and slurry, which reduces the yield of diesel and slurry. Finally, gasoline yield increases and gasoline olefin content decreases.

Advances in processing high-proportion intermediate-base vacuum resid (VR).
A DTFB allows a wide adaptability of raw materials and can even break through the bottleneck of the selection of catalytic cracking raw materials to realize the long-term safe and stable operation with high-mixing ratio and high-carbon residue raw materials. With the newly developed catalyst rich in intracrystalline mesoporous Y-type molecular sieve, the gasoline yield reaches 44.6% when the catalytic cracking raw material contains 46.6% intermediate-base VR (**TABLE 4**).

The coke produced by this unit can use the newly-developed 10 MPa-grade steam generation technology to make full use of the characteristics of heavy oil catalytic cracking of a large steam production load and high thermal energy. This can increase the steam pressure of waste heat boilers and external heat extractors to high pressure levels (10 MPa). Therefore, 280 t/hr of high-pressure steam produced by the heavy oil catalytic cracking unit with an annual capacity of 2.8 MMtpy will be sent to the steam turbine unit (25 MW) for power generation through the system pipe network. After the stable operation of the high-

TABLE 4. Overview of DTFB for processing heavy oil with high residue content

Company	JM
Feedstock	
Density (20°C)/(kg·m⁻³)	939.1
CCR, %	6.55
Hydrogen content, %	11.91
Product distribution, %	
Dry gas	3.62
LPG	20.34
Gasoline	44.6
Diesel	13.75
Slurry	5.69
Coke	11.8
Loss	0.21

pressure steam system, the company's power center changed. Two 130-t/hr circulating fluidized bed (CFB) coal-fired power boilers were shut down, and the catalytic cracking unit became the company's new power center.

Takeaway.
A DTFB is a multi-flow single-vessel fluidized bed that is organically composed of a transport bed, a fast fluidized bed and a turbulent fluidized bed. It has the characteristics of multi-flow and multi-temperature zones, and has developed into an open reactor engineering platform that is suitable for processing various types of distillate oil or heavy oil with high residue content. On this platform, a series of new technologies, such as a catalytic cracking technology for producing ultra-low olefin gasoline and a catalytic cracking technology for producing more propylene and marine fuel oil components, have been developed, injecting new vitality into catalytic cracking technology development. **HP**

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How hydroprocessing feed filtration system design impacts process reliability and efficiency

Oil refining is an exceptionally complex industry, with much of the inherent complexity stemming from wide regional variances in crude quality and composition, plant capabilities and the types of products produced. This creates the need for a broad range of equipment, processes and technologies, which can vary in quality, performance and design.

When considering process filtration, some refiners explore innovative solutions for solids contaminant control, while others simply elect to maintain the status quo. Low-efficiency or undersized filtration systems can lead to frequent and prolonged process upsets, as well as downtime due to equipment fouling, repeated filter changeouts and/or higher process-related operating costs. Additionally, frequent filter changeouts result in higher direct consumable costs, along with indirect costs related to safety, labor, inventory and disposal.

The most significant cost in substandard filtration lies in potential damage to the catalyst beds of hydrotreaters and hydrocrackers. Many operators do not fully realize the impact of inefficient or insufficient filtration in these units, and they simply view filtration as an insignificant piece of equipment on a piping and instrumentation diagram (P&ID). However, insufficient filtration, specifically the lack of particle removal efficiency, has a substantial impact on operational reliability and costs.

Hydrotreaters are units that use hydrogen to remove impurities (such as sulfur) from petroleum cuts (**FIG. 1**). Hydrocrackers are units that use hydrogen for the conversion of heavy cuts into lighter fractions such as naphtha, kerosene and gasoils (**FIG. 2**). Both types of reactors use a fixed bed of catalysts (along with pressure, temperature and hydrogen) to cause the desired chemical reaction.

These units are the heart of the refinery and are critical to downstream processes and product specifications. Fixed-bed reactors are often set up in series and are used for low-to-medium metal content in feeds. These reactors have graded beds and progress from hydrotreatment to hydrocracking.

Hydroprocessing filtration. The purpose of feed filter filtration for both hydrocrackers and hydrotreaters is to prevent fouling of the catalyst bed. Historically, filter designs vary because the quality and characteristics of crude oil differ greatly by region and classification. For example, the sulfur content in sweet light crude is generally 0%–0.5% of weight, while in lower-quality heavy sour crude, it can be upwards of 5%.

This is significant because in the next 20 yr–30 yr, the market expects to witness a growing movement toward lower-quality crudes, as well as toward bio-sourced feedstocks from plant-based and animal-based oils. These changes will result in completely different sets of filtration challenges, and these trends may also be accompanied by stricter environmental specifications—all of which place an increased demand on catalyst bed protection.

Nevertheless, protecting the catalyst bed by providing reliable and predictable effluent fluid quality is the primary goal of any properly designed filtration

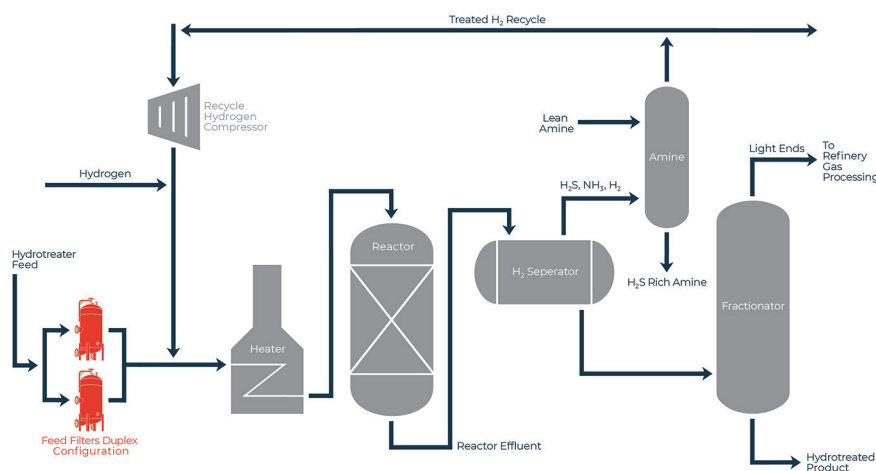**FIG. 1.** Hydrotreaters remove impurities, such as sulfur or nitrogen, and are designed for specific operations. Hydrotreater catalysts are composed of a porous alumina support with a coating of metallic sulfides and are approximately 0.0625 in. in diameter. Common applications include gasoline, naphtha, kerosene and gasoils, as well as biofuels, which present a broader range of applications and challenges.

system. For hydroprocessing units, the feed filter provides a sacrificial system

As a result, operators tend to default to antiquated and/or undersized designs,

area, higher filter particle retention efficiencies and total cost of ownership.

Upgrading the design of the filter system to the latest technology represents a giant step forward in optimizing refinery operations through proper catalyst protection while minimizing total cost of filtration and improving on predictable reactor performance.

that removes undesirable contaminants that can cause reactor fouling. A well-designed feed filter system will prevent problems in both hydrotreater and hydrocracker applications by allowing the reactors to reach full catalyst life and to enter scheduled turnarounds as planned. Although they are replaceable, filters should be given serious consideration, within the context of ensuring trouble-free refining operations, to optimize refining margins and minimize downtime. Unfortunately, this careful consideration does not always occur, as feed filters are often viewed as a "commodity."

or they simply choose the lowest-cost option. Because of the importance of catalyst bed protection, a more comprehensive view should be taken when determining the selection of a filter.

Determining a properly sized filtration system reflects a struggle between capital and operational expenditures (CAPEX/OPEX). CAPEX budgets may call for smaller vessels, which can result in poor performance and higher changeout frequency. OPEX is better served by a filter system sized on criteria that includes inlet particle size distribution, suspended solids concentration, higher filter surface

The economic relationship between the filter and reactor. To truly evaluate a superior value in a filtration system, it should be viewed as a component of the larger refining process. Ideally, a reactor goes into the scheduled turnaround for catalyst reload every 3 yr to 7 yr, depending on the unit. The reactor should reach terminal differential pressure and low-level activity simultaneously. However, many refiners struggle with this and, due to excessive differential pressure, are forced to shut down operations prematurely. The cause of this is poor feed filter performance, which leads to reactor plugging and inefficient reactions because of contaminate loading from the process feedstock. Signs of this include:

- Reaching catalyst bed differential pressure prematurely
- Requiring scraping of the guard bed
- Restricted throughput
- Leaving the bypass line open to help throughput
- Experiencing reactor hot spots due to channeling.

In addition to poor conversion and lower productivity, bed loading can cause the formation of coke, which will ultimately lead to an early catalyst reload. To prevent this costly measure, it is critical to have proper feed filters and to seek out innovative solutions that enhance the performance and longevity of the reactor.

In evaluating the economics for a feed filter system, the first thing to consider is whether the catalyst bed is being protected. While the catalyst is technically a variable cost, it is easy to obtain the historical expenditures at any given refinery. For example, one major refiner's spend on catalysts and chemicals is displayed in **TABLE 1.**

Outside of the one-time cost of the filter vessel, there are many things to consider when evaluating the total cost of filtration. These may vary greatly from one application to the next, but the following can typically be found to some degree in any system:

- Costs of plant downtime, including loss of production and equipment replacement, if the right filtration technology is not deployed
- Labor costs
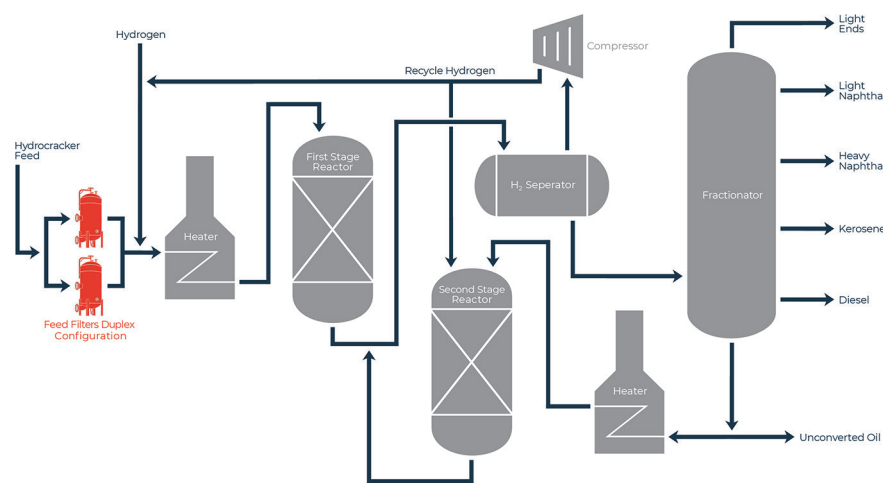
FIG. 2. Hydrocrackers are used for converting heavy feeds (such as vacuum gasoil) into more valuable middle distillates. Depending on the crude slate and processing, there can be an estimated 20% yield in light and heavy gasoline (sent to the reformer), along with the same percentage in kerosene.

TABLE 1. Major refiner's spend on catalysts and chemicals

Catalysts/chemicals	Quantity	Cost
Gas/oil hydrodesulfurization	5.2 metric tpy	$21.9 MM
Hydrocracker	4.4 metric tpy	$12.6 MM
Naphtha hydrotreater	3.5 metric tpy	$1.6 MM
Kerosene hydrotreater	2 metric tpy	$800,000

- Total annual direct filter cartridge cost = total changeouts × cost per changeout
- Filter disposal costs
- Operator hazard-related costs
- Cost of shipping and storing filters
- Other consumable costs per changeout (e.g., fluid losses, vessel seals)
- Rental equipment for catalyst change.

Viewed as an integral part of a larger process design, the selection of a feed filter system at the design phase becomes a more significant consideration. Feed filter performance is crucial for the refiner. A lack of performance can result in millions of dollars in direct material and labor costs, as well as unplanned production losses.

Designing filters for value and improved catalyst performance. A correctly sized, efficient feed filter system provides the most effective way to condition the feedstock prior to reaching the reactor. The feed filter should be located as close to the reactor as economically feasible to ensure that a minimal amount of contaminants is selected between the two. The location for temperature considerations is important, as well. For heavier feedstocks, an increase in the temperature will lower viscosity and cause asphaltenes to go into the solution, thus extending filter life. However, this trade-off could result in a higher-cost design for the filters. While the filters may have a bypass line, this should only be opened in rare or abnormal conditions.

Additional important design and installation criteria include:

- Filter retention efficiencies consistent with the recommendations of the catalyst manufacturer or process licensor—usually 10 μm–20 μm at 99%–99.98% efficiency, depending on catalyst diameter and reactor packing density
- Ergonomically designed vessels that are duplexed (2 × 100%) for ease of changeout
- Vessel sizing to accommodate upset conditions to avoid bypass or rate reductions
- System sized on both flow and potential contaminant loading
  - No greater than 0.5 gpm/ft^2 flux rate to maximize cartridge dirt holding capacity (DHC)
  - Consideration of total suspended solids and particle size distribution
  - Consideration of ancillary contaminants, such as asphaltenes, as these can be captured by the filter
- Media tested according to industry standard ASTM F795-88 (1993), including single-pass, initial efficiencies to ensure consistency and performance integrity
- Pressure drop based on actual operating conditions
- Considerations for future throughput potential
- Media, support layers, component, and elastomer chemical and thermal compatibility

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- Vessel design that has an optimized number and geometry of elements to minimize wasted space
- Filter element design with an optimum effective surface area.

Recent innovations such as finer fiber diameters, higher media porosity and greater gradient density have led to important benefits, including lower pressure loss, higher DHC, reduced particle capture size and improved efficiencies. However, the performance of traditional cylindrical filters can only be pushed so far. Much of this is due to the inherent limitations of their physical shape. Traditional cylindrical filters leave considerable dead space in a filter vessel, particularly when multiple filters are placed in a housing. A trapezoidal design minimizes the dead space and maximizes the effective filter media surface area in a pressure vessel (**FIG. 3**).

By minimizing dead space, trapezoidal filters can provide up to 176% more effective surface area than cylindrical filters, depending on the configuration of the filter (**TABLE 2**). This results in lower pressure drops and longer online life. The density of the trapezoidal configuration also results in fewer filters to stock, change out and dispose. Additionally, the use of trapezoidal filters in place of cylindrical elements has the potential to reduce costs in areas such as shipping, storage and changeout, thereby presenting operating units with a significant overall cost reduction.

Greater surface area equals longer filter cartridge life. The increase in surface area has a direct impact on filter cartridge life. This is because a filter cartridge's DHC is directly related to the amount of usable surface area in the cartridge itself. When the surface area is increased, the corresponding decrease in fluid flow per unit area drives up the DHC. By doubling the surface area, a filter system can increase filter life by up to four times, as illustrated in Eq. 1:

$$Le = (Ae \, / \, Ao)^n \qquad (1)$$

where:
  Le = Extended filter life
  Ae = Extended surface area
  Ao = Original surface area
  n = The ability of the solid to form a porous cake.

When various factors—cartridge life, reliable catalyst bed performance and uptime—are taken into consideration, a clearer view of the importance of filter selection begins to take shape. After several months of successful operations, one facility using the proprietary trapezoidal filters[a] recorded measurable benefits in several key areas, including an 84% increase in effective surface area; a 400%–500% increase in filter life; lower direct consumable costs; fewer process upsets; and reduced labor, shipping and disposal costs.

Takeaway. For refiners that place a priority on minimizing downtime, optimizing performance, protecting the longevity of catalyst reactors and minimizing the overall lifecycle costs of their filtration systems, upgrading the quality and construction of the filter system represents a giant step toward achieving these goals. Proper feed filter filtration can prevent millions of dollars in lost production, along with direct losses related to material and labor costs.

An important step toward optimizing performance for the industry is to include ASTM F795-88 (1993) testing standards to determine cartridge filter efficiency. Furthermore, by requiring filter manufacturers to adhere to a recommended sizing specification of 0.5 gpm/ft^2 flow per unit area of media or less, operators can put all manufacturers on a level playing field and evaluate products accordingly.

As a result, a more accurate measure of true lifecycle cost can be evaluated, which incorporates the filter life (as determined by DHC) and ancillary costs, such as shipping, storage and changeout times. Furthermore, migrating away from existing cylindrical filters toward more innovative solutions (such as trapezoidal filters) can help operators significantly improve both value and efficiency. This will move them toward a new standard in overall filtration system performance. **HP**
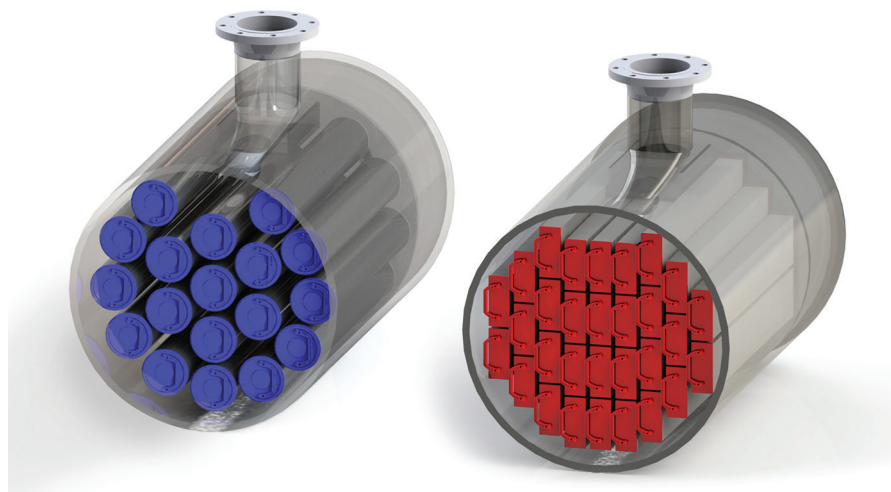
FIG. 3. A proprietary trapezoidal-shaped cartridged filter[a] (right) increases the usable surface area up to 169% vs. traditional cylindrical element designs (left).

TABLE 2. Increased packing density and surface area of trapezoid-shaped elements

Vessel diameter, in.	Number of cylindrical 740 style elements	Number of trapezoidal filter elements	Increase in packing density, %	Increase in surface area, %
18	4	6	50	Up to 176
24	8	11	38	Up to 153
30	13	19	54	Up to 169
36	21	30	43	Up to 163
42	29	38	31	Up to 141
48	37	50	35	Up to 148

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Choosing controlled and optimal parameters for the DHDS unit

Environmental considerations and stringent government regulations drive incessant interest and efforts to decrease diesel sulfur content to ultra-low levels. New deep hydrodesulfurization technologies configured to meet diesel product sulfur specifications of less than 10 ppm continue to attract the attention of refiners. The medium-pressure ultra-low-sulfur (ULS) diesel hydtrotreating unit converts sulfur to hydrogen sulfide (H_2S) in the presence of hydrogen (H_2) and catalysts, with the H_2S removed at a later stage. Significant effort is being made to optimize the process and operations to comply with Euro-5 quality specifications for diesel sulfur content and maintain an economic balance.

The improvement in the process requires an understanding of various factors that control outlet sulfur concentration, so that refiners and technology providers can design and operate the hydrodesulfurization unit as a controlled operation to achieve the desired results. This article examines the relationship of catalyst activity and reactor operating factors with conversion rate and sulfur concentration in outlet diesel. Process simulations were performed to analyze how each of the considered variables impact the outlet sulfur content. The results show that an increase in each of the contributing factors (i.e., reaction temperature, H_2 purity and catalyst activity) improved the conversion rate of reaction, thus a decline in the outlet sulfur concentration in diesel was achieved. However, optimal parameters must be set to prolong catalyst life and maintain excellent and cost-effective outcomes.

Process scheme. The diesel hydrodesulfurization (DHDS) unit is designed to hydrotreat straight-run diesel from the crude distillation unit and diesel from bottom upgradation units such as the thermal cracker or visbreaker to achieve a target sulfur specification of 10 wppm.

The H_2 requirement of the DHDS unit is fulfilled from the reformer (if available in the refinery) and a separate H_2 plant. The feed is pumped to a required reaction pressure of 53 barg, combined with the H_2 stream, and introduced to a reactor after being preheated by heat exchangers and furnaces to a temperature of 318°C. The reaction is facilitated using a high-activity cobalt-molybdenum (CoMo) catalyst in a fix-bed reactor, where conversion of sulfur to H_2S takes place. The reaction is a quenched reaction as the reaction products pass from the heat exchanger and cooler to a cold separator at reduced pressure. The H_2-rich vent gas from the cold separator is routed to the amine contactor. Lean H_2 gas from the amine contactor is routed to the recycle gas compressor to minimize consumption of makeup H_2, while the rest is vented. The liquid from the cold separator is routed to a distillation column where desired desulfurized diesel is obtained as a bottom product.

Case Study feed data. A simulation-based case study was performed to present an analysis of sulfur outlet concentration, with respect to different parameters and recommendations made against each scenario to achieve optimum results. The following feed data was considered and used in the simulation for evaluation: a sulfur concentration in the diesel feed of 1 wt%; a feed flowrate of 32,920 bpd; an operating pressure of 53 barg; and the use of a CoMo catalyst.

Relationship between catalyst activity and sulfur outlet concentration. Catalyst activity is a function of chemisorption of reactants on the catalyst surface, which also affects the rate of conversion of reaction. Coking or carbon deposition, sintering and poisoning of catalysts all refer to physical or chemical deactivation of catalyst active sites, resulting in a decrease in catalyst activity and impacting catalyst performance. As a result, the sulfur content in outlet diesel is high and target specifications are not met. Sometimes, the molecules acting as a catalyst poison get chemisorbed on catalyst active sites, resulting in irreversible changes to the geometric structure of the catalyst's surface or the chemical nature of active sites. As a result, catalysts must be replaced or regenerated. Therefore, it is important to handle catalysts as per industry standard practice and avoid/minimize carbon deposition and catalyst poisoning.

Carbon formation and deposition on the catalyst can be avoided by providing high partial pressure of H_2 in a DHDS reactor, whereas sintering can be avoided by selecting catalyst constituents that have high thermal stability. To preserve catalyst activity, the licensor or technology providers choose catalyst formulation, design, pore size distribution and pellet size as per diesel feed composition.

A case study was performed to analyze the direct impact of catalyst activity on the conversion of reaction and sulfur outlet concentration in the DHDS process.

Case Study results. With increases in catalysts activity, the overall conversion of reaction increases, which utilizes more H_2 to convert sulfur to H_2S, thus reducing diesel outlet sulfur concentration (**TABLE 1**). Commercially available hydrodesulfurization catalysts are designed to achieve ULS diesel product. However, catalyst activity must be monitored and assessed for a cost-effective process and operation.

Relationship between H_2 purity and sulfur outlet concentration. H_2 is added and recycled—with makeup H_2—as one of the feed streams to react with diesel in the reactor to convert free sulfur present in diesel to H_2S, which will be separated in downstream units, thus producing ULS diesel. If H_2 is not recycled, the process economics of the unit becomes infeasible.

H_2 partial pressure in the reactor is directly related to the purity of the H_2 fed to the reactor as a feed stream (fresh H_2 + recycled). The lower partial pressure of H_2 leads to a decrease in reaction conversion and higher sulfur concentration in the product. Therefore, it is important to ensure the high H_2 purity in the feed stream and the removal of non-H_2 components in the recycle stream.

A case study was performed to determine and evaluate the effect of H_2 purity on the conversion of reaction and the sulfur concentration in the DHDS product. With the change in H_2 purity, other factors also change and have a cumulative impact on sulfur outlet concentration.

Case Study results. The outcomes of the case study indicate the correlation between increasing sulfur outlet concentra-

tion in diesel with a decrease in H_2 purity (**TABLE 2**). These results confirm that high H_2 partial pressure and purity must be maintained to achieve desired low-sulfur concentration in the DHDS product.

Relationship between reactor temperature and sulfur outlet concentration. Sulfur impurities present in diesel are typically in the form of mercaptans, sulfides, disulfides, cyclosulfides and thiophenes. In refinery operations, operators may encounter significant variations in the types of sulfur impurities present in diesel. Since high temperatures drive higher conversion in the DHDS reactor, high-temperature operations are employed to ensure on-spec diesel production even with varying sulfur content in the feed stream.

Activation energy escalates with an increase in reaction temperature due to an upsurge in the number of molecules involved in the hydrogenation reaction. This phenomenon also involves changes in the physical properties of diesel (i.e., an increase of diffusivity and a decrease in viscosity and surface tension), which ultimately promotes the H_2 absorption rate in diesel and catalyst pores to reach the active sites where the reaction occurs, thus converting sulfur to H_2S.

A case study was performed to analyze the effect of reaction temperature on catalysts (life and deactivation rate) and performance of the DHDS unit with respect to the sulfur outlet concentration of diesel.

Case Study results. The results indicated that increasing the reaction temperature reduces sulfur content in product diesel; however, optimum temperature selection is important to maintain an economical balance between on-spec diesel production and catalyst life and product yield (**TABLE 3**). Also, high-temperature operation in the DHDS reaction should be monitored and controlled closely, as high reaction temperatures can result in over-cracking or catalyst coking, which reduces catalyst life and yield.

Takeaway. Important operating parameters such as reactor temperature, catalyst activity and H_2 purity have a significant impact on outlet sulfur concentration. Understanding the impact of these parameters is essential for selecting optimal parameters to ensure desired product specifications and economic operation of DHDS processes. **HP**

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MOHIB SHAMSHAD is a Senior Process Engineer. He has 8 yr of experience in process design engineering. He earned a BE degree in chemical engineering from the University of Karachi, Pakistan, and an ME in chemicals from NED University of Engineering and Technology, Karachi.

TABLE 1. As catalyst activity increases, the overall conversion of reaction increases, leading to a lower outlet sulfur concentration in diesel

No.	Catalyst activity	H_2 consumption with respect to feed, ft³/bbl	Overall conversion, wt%	Outlet sulfur concentration in diesel, ppm
1	0.7	364.1	9.9	95
2	0.8	403.5	11.3	30
3	0.89	436.5	12.7	9

TABLE 2. The case study results showed a correlation between increasing sulfur outlet concentration in diesel with a decrease in H_2 purity

No.	H_2 purity, %	Average reactor temperature, °F	Purge gas with respect to feed, ft³/bbl	Overall conversion, wt%	Sulfur outlet concentration in diesel, ppm
1	83.5	653	4.2	11.1	25
2	85	655	26.2	11.6	17
3	87.5	657.8	73.1	12.53	9

TABLE 3. Increasing the reaction temperature reduces sulfur content in product diesel

No.	Change in reactor inlet temperature, °F	Average temperature of the reactor, °F	Deactivation rate, °F/bbl/lb	Catalyst life, d	Cumulative impact on sulfur outlet concentration in diesel, ppm
1	585	631.1	0.9384	184.6	98
2	592	642.9	1.245	116.4	30
3	598	653.1	1.61	74.75	9

The 1940s: Global conflict, FCC, 100 octane, synthetic rubber—Wartime necessitates advancing technologies

Hydrocarbon Processing continues its look at the history of the hydrocarbon processing industry (HPI). The first installment detailed the origins of the global refining and petrochemical industries. In the February issue, major refining and petrochemical discoveries of the 1930s were discussed, including the discovery of catalytic cracking and polyethylene; the evolution of coking and gasification; the production of polystyrene, nylon, polyester, resins, epoxies and polyurethane; and the inception of the jet engine.

The following will detail how the HPI continued to evolve during the 1940s.

The onset of fluid catalytic cracking (FCC).
In 1936, Eugene Houdry started up the first Houdry unit at Sun Oil's Marcus Hook refinery in Pennsylvania (U.S.). The novel fixed-bed catalytic cracking unit was instrumental in evolving the gasoline production process. For example, approximately 50% of the 15,000-bpd unit produced high-octane gasoline, which was double the production of conventional thermal processes.[24] However, the novel Houdry process—a significant advancement vs. the thermal cracking process—was unable to satisfy increasing global demand for gasoline from vehicles and the aviation industry.

In the early 1940s, Standard Oil of New Jersey and Davison Chemical (the company would later become W. R. Grace & Co.) collaborated on developing powered catalyst and an improved catalyst circulation design vs. the Houdry process. The companies were joined by the Massachusetts Institute of Technology (MIT) and M. W. Kellogg.[23]

Through significant research, MIT professors Warren Lewis and Edwin Gilliland improved Houdry's design. One of the major changes was improving catalyst circulation—the new design enabled the catalyst to pass through both the reactor and regenerator. Their patent was the basis for Standard Oil of New Jersey's 100-bpd pilot plant in Baton Rouge, Louisiana (U.S.).[23] The newly designed pilot plant was tested and, after a few modifications, was shut down and redesigned into a full commercial unit. On May 25, 1942, Powdered Catalyst, Louisiana 1 (PCLA) Model 1 went online (**FIG. 1**), marking the first use of a commercial catalytic cracking process using powdered catalyst.[23] The plant's catalyst was supplied by Davison's Curtis Bay Works facility in Maryland, which also began operations in May 1942—three months later, *The Refiner and Natural Gasoline Manufacturer,* the forerunner to *Hydrocarbon Processing,* was retitled *Petroleum Refiner;* the name change reflected the significant advancements and broader scope of petroleum processing. The Curtis Bay plant was the world's first synthetic FCC production facility, and, in 1947, Davison established the refining industry's first technical services facility for fluid cracking catalysts.[47]

Over the next 2 yr, several new FCC units were built in the U.S. The new refining process helped to significantly increase production of gasoline motor fuel and aviation gasoline, which was crucial in aiding the Allied powers in World War 2 (WW2).

The world engages in conflict.
On September 1, 1939, Germany invaded Poland. The invasion caused European allies to mobilize against Germany, setting off the largest and bloodiest conflict in human history. Central to both the Allies and Axis

FIG. 1. View of Standard Oil of New Jersey's PCLA Model 1 plant in Baton Rouge, Louisiana—the first use of a commercial catalytic cracking process using powdered catalyst. Photo courtesy of the American Chemical Society.

powers' military operations was the ability to produce refined fuels. Oil and refined fuels were imperative during the war. Without fuel (gasoline and aviation gasoline), tanks could not run, planes would not fly, battleships and other marine vessels are trapped in port, and thousands of other vehicles (e.g., jeeps) become obsolete. Oil was also indispensable for lubricating guns and machinery both in the field and to fuel domestic industrial manufacturing.

The Allies—especially the U.S.—controlled most of the world's oil production. Conversely, Germany lacked any kind of oil production, which was a major factor that eventually led to its demise. However, Germany did have a substantial amount of coal reserves. To fuel its war machine, Germany primarily used coal conversion

FIG. 2. The British Spitfire used 100-octane fuel-powered Rolls-Royce Merlin engines, enabling them to gain a decisive advantage over the German Luftwaffe during the Battle of Britain in WW2. The U.S. significantly boosted 100-octane fuel production, enabling the Allies to gain air superiority against the Axis powers. Photo courtesy of the Imperial War Museum.

FIG. 3. WW2 poster stressing the importance of high-octane aviation fuel. Spoken by U.S. Chief of Naval Operations Ernest King, the slogan "Oil is ammunition" was used for promotional posters during the conflict. Source: U.S. National Archives and Records Administration.

processes for synthetic-fuels manufacturing. More than 90% of Germany's aviation gasoline and half of its total domestic petroleum products production came from synthetic fuel plants.[48] These plants primarily used the Bergius process and the Fischer-Tropsch process, among others.

Japan suffered from the same challenge as Germany. The country had no oil production and virtually no refining system to produce fuels for its war effort. Japan did have major coal reserves and tried to venture into synthetic fuels production; however, it lacked the technical expertise and specific alloys and catalytic metals required for synfuel production.[49]

Once the U.S.—the primary supplier of oil and finished products to Japan—cut off oil supplies to the island nation, Japan began a strategic military offensive in the South Pacific, seizing oil fields developed by Royal Dutch Shell in the Dutch East Indies (i.e., Indonesia) and Borneo, which also contained 90% of the world's natural supply of rubber.[49] However, the Axis powers could not compete against the manufacturing juggernaut of the Allied nations.

Several new technologies and initiatives were integral in the Allied war effort against the Axis powers. These included the production of 100-octane aviation gasoline, a boost in domestic refined fuels capacity, a more efficient way to produce pure toluene and cooperation for the development of synthetic rubber.

100 octane: A decisive advantage in aerial superiority. In the mid-1930s, U.S. aviator Jimmy Doolittle joined Shell Oil Co. as Aviation Manager. His primary responsibility was to develop aviation fuels for military and civilian applications. Up until this time, both automobiles and aircraft ran off 87-octane gasoline levels. However, the lower-rated fuel severely affected aircraft engine performance, negatively impacting speed, climb rate, service ceiling and overall performance, especially at higher altitudes. Higher octane aviation gasoline (i.e., 100 octane) could fuel high-performance aircraft engines, boosting the performance of fighter planes.

After lobbying the U.S. Congress, Doolittle convinced the U.S. Army to adopt 100-octane aviation fuel as the standard fuel for aircraft. However, the fuel was extremely expensive to produce and prohibitively high to sell—the cost of 100-octane fuel was approximately $20/gal vs. less than $0.20/gal for regu-

lar automobile gasoline.[50] The solution to this challenge came from a new process in operation at the Marcus Hook refinery in Pennsylvania (U.S.). The process was a catalytic cracking process developed by a French engineer: Eugene Houdry.

The Houdry process was greatly enhanced by octane-boosting processes, the most notable being invented by Russian-born chemists Herman Pines and Vladimir Ipatieff. Ipatieff, the Director of Chemical Research at Universal Oil Products (UOP) and a professor at Northwestern University in Chicago, was responsible for the development of solid phosphoric acid—a highly active refining catalyst created by treating silica with phosphoric acid.[51] The catalyst was instrumental in increasing octane levels of gasoline. Ipatieff worked closely with fellow UOP colleague Herman Pines in the 1930s. The pair were instrumental in developing new polymerization, alkylation of aromatic compounds (i.e., alkylation)—Phillips (later called ConocoPhillips) invented the hydrofluoric acid (HF) alkylation process in the early 1940s to produce high-octane aviation gasoline[52]—and isomerization of paraffins (i.e., isomerization) to boost octane levels in aviation gasoline to 100. These new processes enabled the U.S. refining industry to produce affordable high-octane aviation gasoline, which would play a decisive role in WW2.

By 1940, the U.S. was producing more than 4.2 MMgpm of 100-octane aviation gasoline[53]—the standard fuel for the U.S. Air Force (referred to as the U.S. Army Air Corp prior to entrance in WW2). As war was declared in Europe, the U.S. gained its first customer for 100-octane aviation gasoline: Great Britain. The high-octane fuel powered Rolls-Royce Merlin engines inside British Hurricane and Spitfire fighter jets (**FIG. 2**), enabling them to gain a decisive advantage over the German Luftwaffe—most of Germany's fighter jets ran on 87-octane aviation gasoline. The 100-octane aviation fuel was an invaluable asset that helped Britain push back German air attacks during the Battle of Britain and aided Allied powers in establishing air superiority (**FIG. 3**).

TNT. Trinitrotoluene (TNT) was first discovered by German chemist Julius Wilbrand in 1863. However, the first use of the material was for yellow dye. Approximately 30 yr later, German chemist Carl Häussermann discovered its explosive properties.[54]

TNT was used by Germany and other militaries starting in the early 1900s.

According to literature,[55] Standard Oil Development (the company would later become Exxon) detected toluene in product streams from thermal reforming experiments on a petroleum-based naphtha. This discovery led to a new source to produce a significant amount of pure toluene. However, the produced product did not meet nitration-grade requirements. Upon using catalytic reforming, the process produced a 99+% toluene stream that could be nitrated.[55] From 1940–1945, toluene production in the U.S. topped 484 MMgal, with nearly half being produced by Standard Oil's subsidiary, Humble Oil and Refining Co. Approximately 15% was produced by Shell.[56] This significant increase in production enabled the Allied powers to receive a steady stream of explosive materials.

Synthetic rubber. Although the discovery of synthetic rubber dates to the late 1870s (French chemist Gustave Bouchardat created a polymer of isoprene), the first true synthetic rubber was created and patented by German chemist Fritz Hofmann in the early 1900s.[57] During WW2, the Allies were nearly cutoff from supplies of natural rubber—the Japanese occupied rubber producing areas in Southeast Asia, which represented 90% of the world's natural rubber production.[58] Without rubber, Allied vehicles and planes could not be built or repaired.

As a solution, the U.S. government partnered with four rubber companies—B. F. Goodrich, Firestone Tire and Rubber Co., Goodyear Tire and Rubber Co, and the U.S. Rubber Co. (the company would later become Uniroyal)—to find a solution to the rubber supply crises. However, to produce synthetic rubber, butadiene—its basic raw material—is needed. To produce much-needed supplies of butadiene, several U.S. refiners built new facilities to produce the product that would be used to increase synthetic rubber production.

Researchers at the four big tire companies set out on new processes to increase synthetic rubber production in the U.S. In 1940, while working at B. F. Goodrich, Waldo Semon—the inventor of an improved process for PVC production—invented a process for the copolymerization of butadiene with methyl methacrylate. The cost-effective synthetic rubber produced was marketed under the name Ameripol. Goodyear produced its own synthetic rubber—the process was patented by Ray Dinsmore—called "Chemigum." The other rubber companies patented processes to increase synthetic rubber production, as well.[59]

However, in 1942, synthetic rubber producers were needed to boost production to aid the Allied war effort. The four rubber companies, along with the U.S. government, agreed upon a common process to produce synthetic rubber called GR-S (government rubber styrene), which was similar to Bina S developed by Germany. By 1945, the U.S. increased GR-S production to approximately 920,000 tpy.[59] Due to this manufacturing juggernaut, Allied forces did not suffer from a shortfall in synthetic rubber for military equipment and vehicles.

Cyanoacrylates. In 1942, Harry Coover—while working at the Eastman Kodak company in the U.S.—was conducting experiments with cyanoacrylates. He was attempting to develop materials to build clear plastic gun sights for the Allies in WW2. However, while working with the materials, he noticed that it stuck to everything, making it very difficult to work with. According to literature, moisture caused the chemicals to polymerize, and since virtually all objects have a thin layer of moisture on them, bonding would occur in nearly every testing instance.[60] Since the material was highly adhesive, the researchers rejected the commercial use of it.

It was not until 1951 that Coover and fellow researcher Fred Joyner recognized the potential of cyanoacrylates as a quick bonding substance. His team was researching heat-resistant polymers for jet airplane canopies. These tests showed the unique adhesive properties of cyanoacrylate—the adhesive required no heat or pressure to bond.[60] Several years later, Eastman Kodak sold the material as Eastman 910, later marketing the material as it is known today: Super Glue. The material—still in use today for many applications—has a unique story in that it was discovered by accident, twice.[61]

Silicones. Although discovered in the 1850s, commercial silicones research and development would not take off until the 1930s. Early research was conducted by American chemist James Franklin Hyde while working at Corning Glass Works (**FIG. 4**). By using English chemist Frederic Stanley Kipping's procedure for cre-
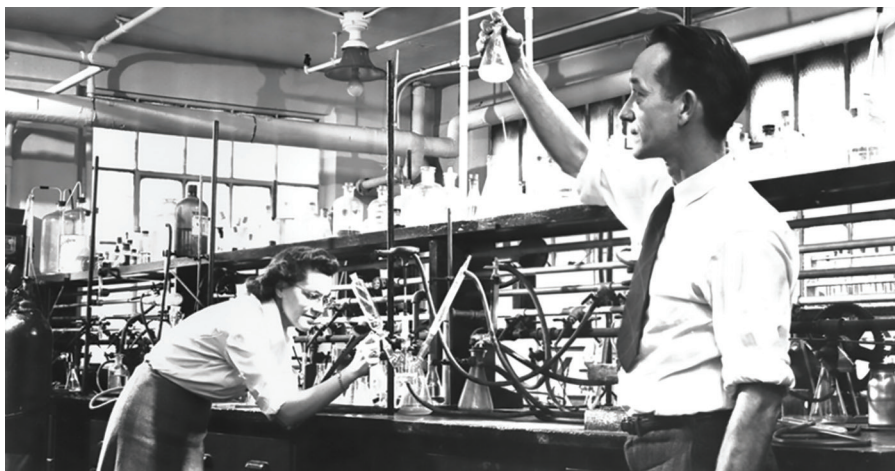
FIG. 4. James Franklin Hyde works with a colleague on experiments in the Corning Glass Works' lab. Photo courtesy of Dow Corning.

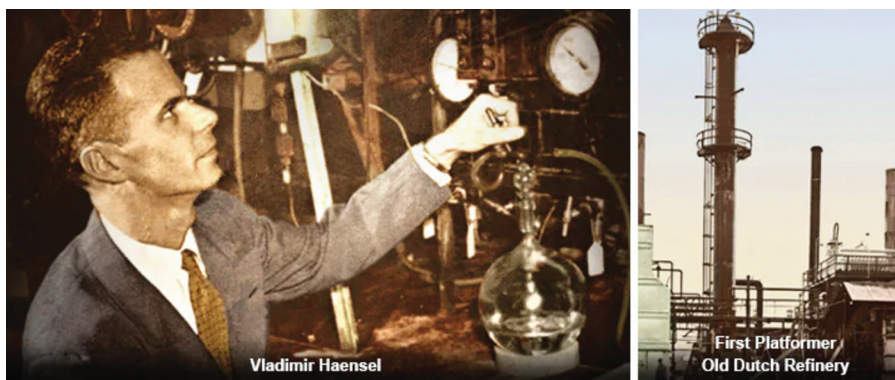Vladimir Haensel

First Platformer
Old Dutch Refinery

FIG. 5. Vladimir Haensel (left) developed the Platforming process. The first Platforming unit (right) went online in 1949 at Old Dutch Refining Co.'s refinery in Michigan (U.S.). Photo courtesy of Honeywell UOP.

ating organic silicon compounds, Hyde was able to create a synthesized fluid that hardened into a rubbery mass.[62] Kipping pioneered work in silicone polymers, even coining the name "silicone" in 1904.

Hyde's discovery enabled Corning to produce high-temperature motors and generators. Silicones were used extensively in ships and planes during WW2 as a cable and wire insulator.[62] Hyde's work created the first commercially useful silicone product and led to the formation of the Dow Corning Corp. in 1943—a JV between Dow Chemical Co. and Corning Glass Works. The company's primary focus was to develop silicone products, including manufacturing products for the U.S. military in WW2. The company's first product was Dow Corning 4, an ignition sealing compound that made high-altitude flight possible. The compound prevents corona discharge, enabling aircraft to remain at 35,000 ft for 8 hr. This bene-

fitted the Allied powers since planes could be flown to the UK and North Africa vs. transporting them by ship, significantly reducing the risks of them being bombed and destroyed by Axis forces.[63,64]

Silicone continues to be widely used in many different industries and applications, including in automotive, construction, energy, electronics, chemicals, coatings, textiles and personal care, among others.

Unconditional surrender and postwar discoveries. On May 7, 1945, Germany unconditionally surrendered to the Allies. Japan did the same on September 2, 1945. These events marked the end of the 7-yr global conflict.

The end of the European conflict also saw the breakup of the largest chemical and pharmaceutical company in the world, IG Farben. The company was formed in 1925 as a merger of six chemi-

cal companies—BASF, Bayer, Hoechst, Agfa, Chemische Fabirik Griesheim-Elektron and Chemische Fabrik vorm. Post WW2, the company was broken into several different entities. Agfa, BASF and Bayer continued operations. Hoechst acquired several other companies over the next several decades, as well as spinning off portions of its business into independent companies, such as Clariant. Hoechst is presently a subsidiary of the French pharmaceutical company Sanofi.

Although WW2 had ended, the global refining and petrochemicals industries were just beginning. New technologies and discoveries continued to be made through the rest of the 1940s.[65] In 1947, American chemical engineer Vladimir Haensel conducted experiments using platinum catalysts for upgrading petroleum. However, at the time, the use of platinum catalyst was thought to be impractical and uneconomical due to the costs of the precious metal. Haensel's research showed that using miniscule amounts of platinum (0.01%) was enough for an effective process.[66,67] This research led to a novel process to produce gasoline with a higher octane rating: Platforming. Haensel's Platforming process also generated a higher yield of aromatic hydrocarbons, which are used in manufacturing plastics.[66,67] The process was commercialized by UOP, and the first Platforming unit (**FIG. 5**) was built in 1949 at Old Dutch Refining Co.'s refinery in Michigan (U.S.). The Platforming process was instrumental in the eventual removal of lead from gasoline.

The 1950s. Post-WW2 saw a significant increase in oil consumption and economic development in Europe and the U.S. New chemical and refining discoveries would continue to improve the lives of people around the world. The evolution of the global refining and petrochemicals industry in the 1950s will be examined in the April issue of *Hydrocarbon Processing*. This includes the discovery of polypropylene, high-density polyethylene, new catalyst designs, the first use of a computer control system in refining operations and several other advancements in refining and chemicals production technologies. **HP**

LITERATURE CITED

Complete literature cited available online at
   www.HydrocarbonProcessing.com

Operations expand and technologies advance during global conflict: Excerpts from the 1940s

Application of x-ray inspection on oil refining equipment
H. R. Isenburger, January 1940

This articles details several case studies on the use of x-ray technology for inspection purposes. This includes for the inspection of casings, forgings and welded structures, among others.

Calculating gasoline octane rating from gravity and ASTM distillation
R. B. Cox, February 1940

Determining the octane number of gasoline is an expensive and time-consuming operation. Many attempts have been made to correlate this octane number with various physical properties of gasoline. The purpose of this paper is to present methods of calculating the octane rating of any gasoline by using only its API gravity and ASTM distillation.

Synchronized controls improve boiler operation
May 1940

Synchronizing the controls in the boiler room of a gasoline plant was accomplished through an arrangement of valves, piping and linkage, so that the draft through each boiler is automatically adjusted to the quantity of steam generated and the amount of fuel consumed.

Aviation gasoline plant near the Arctic Circle
R. E. Parkhurst, July 1940

This article examines the completion of the northern-most refinery in operation. The 840-bpd refinery has been developed by Imperial Oil Ltd. The facility is located at Norman Wells on the Mackenzie River in Northwest Territories, Canada, approximately 100 mi from the Arctic Circle.

The behavior of gasoline-coal fuel in spark-ignition engines
J. E. Hedrick, August 1940

Discussions have been made regarding the use of petroleum and pulverized coal mixtures in internal combustion engines. This subject has received more attention in Europe because of the scarcity of motor fuels. This work presents data on actual engine performance where a gasoline-coal suspension was used as fuel vs. the use of only gasoline.

Butyl rubber—A new hydrocarbon product
R. M. Thomas, I. E. Lightbown, W. J. Sparks, P. K. Frolich and E. V. Murphree, October 1940

In developing their new butyl rubber, Esso Laboratories has turned to simple olefins rather than diolefins or more complicated chemical derivatives as the primary raw material. Not only is this an economic advantage, but the availability of such simple olefins from refinery cracking operations makes the process attractive to produce synthetic rubber.

Use of additives in automotive lubricants
F. L. Miller, W. C. Winning and J. F. Kunc, February 1941

Only a few years ago, it was predicted that the motor lubricant of the future would consist of a highly refined mineral-oil base to which small quantities of special chemical agents would be added to secure the properties desired for superior engine lubrication. Today, progress in this direction is so rapid that it appears to be only a matter of time until most, if not all, of the predictions are realized.

The study of water problems in atmospheric cooling systems
D. W. Hearing and D. M. Considine, March 1941

Solutions to challenges in atmospheric water cooling systems in petroleum refining are receiving closer attention because expansion of processes and consequent increased demands of cooling have stimulated the trend toward water conservation through the installation of recirculating water systems.

Production of aviation motor fuel from natural gasoline
K. E. Cody and D. M. Luntz, April 1941

For many years, the principal use of natural gasoline has been to raise the volatility of motor fuel. Consequently, natural gasoline has been sold on a vapor pressure-volatility basis with little regard for other characteristics such as octane blending value and lead susceptibility. With the increased demand for high-octane aviation gasoline and with the depressed market for natural gasoline, many plants are considering manufacturing aviation base stocks as a means of making a larger profit on their production.

Useful products from natural gas
F. H. Dotterweich, May 1941

The growth of natural gasoline production has increased the amount of the byproduct natural gas, which has been marketed as a fuel and source of energy. More recently, natural gas has been used as a raw material for chemical production.

First hydroformer unit put on stream
J. V. Hightower, May 1941

The 7,500-bpd hydroforming unit went online at Pan American Refining Corp.'s refinery in Texas City, Texas (U.S.). The unit is the first commercial installation of this type. It uses a catalytic process to convert low-octane naphtha into 77–80 octane aromatic gasoline containing a small percentage of unsaturates.

Petroleum becomes source of military explosives
B. O. Lisle, August 1941

Trinitrotoluol (TNT) is a preferred explosive because of its high power, great stability and dependability, and safety during handling. The increasing demand for TNT has resulted in the increased demand for toluene. This article looks at what toluene is, and the different processes used to manufacture it.

Refining processes
September 1941

This section was the forerunner to the publication's Refining Handbook. This first iteration details more than two dozen refining processes used in the early 1940s, including distillation, alkylation, catalytic cracking, catalytic polymerization and isomerization, among others.

Turbines for power generation from industrial process gases
J. Goldsbury and J. R. Henderson, December 1941

This article presents the files of application for turbines operated by industrial process gases and natural gases. It provides examples of mechanical details of actual turbines which have been built for such applications, a simple method for calculating the energy available in a pure or a compound gas for specific operating conditions, and the properties of various gases for use in such calculations.

Defense efforts push oil to record levels during 1941
W. R. Boyd, January 1942

Natural gas as a raw material in the production of synthetic ammonia
F. H. Dotterweich, March 1942

Butadiene calls for few departures in equipment or processing
J. V. Hightower, April 1942

Although the petroleum refining industry is turning to the production of raw materials, chiefly butadiene for the manufacture of synthetic rubber, this does not mean that plants will require radically different equipment and fundamentally different processes from those used in the production of ordinary petroleum products.

Importance of butane in this war
R. L. Huntington, May 1942

Natural gasoline manufacturers realize the important part that butanes are playing in the production of materials highly essential for winning the war. Through thermal and catalytic conversion processes, isobutane is being made into isooctane, an invaluable blending agent for aviation motor fuel. Normal butane is being converted into butadiene through dehydrogenation. Approximately three parts of butadiene and one part of styrene make up the principal constituents going into the manufacturing of artificial rubber.

Increasing recovery of liquefied petroleum gases in natural gasoline plants
J. W. Wilson, June 1942

Total sales of LPG have significantly increased over the past 2 yr. The increasing uses for these petroleum gases are leading to accelerating demand.

Practical methods for storing volatile liquids
D. E. Larson, July 1942

In designing a chemical plant or petroleum refinery, provisions must be made for the storage of volatile liquids. The designer will naturally design storage capable of the following results:

1. Retaining each product for the required period without deterioration or loss of quality
2. Retaining the product without loss of volume
3. Storing the product at the lowest possible cost per gallon commensurate with safety
4. Storing the product with the least possible danger from fire.

The War Products issue
October 1942

This issue was dedicated to petroleum products produced to help the Allies during World War 2. The issue focuses on the different processes that produce products such as synthetic rubber, aviation gasoline, aviation lubricants, toluol, alcohol, plastics, etc. The introduction of the issue is copied below:

"Upon their supply and performance rests the fate of civilization. Equally important will be their influence upon human affairs in the peace to come. Petroleum refining rises to meet this challenge and marches on to victory.

The following pages illustrate the present and the future. Photographs show the rubber consuming instruments of war for which the industry's hectic planning and building are being made and the products/fuels produced to excel in battle. The story tells of the peacetime future of these wartime products."

Record crude production and high refinery runs required to meet huge military needs
L. J. Logan, August 1943

Fluid catalyst cracking for premium fuels
E. V. Murphree, H. G. M. Fischer, E. J. Gohr, W. J. Sweeney and C. L. Brown, November 1943

Many large fluid catalyst cracking units are in operation producing highly aromatic aviation basestocks, raw materials for alkylate, synthetic rubber and toluene. These operations have established the fluid catalyst process as an economical basic cracking installation for producing aviation and motor fuels.

Recent developments in Houdry fixed-bed catalytic processes
T. B. Prickett and R. H. Newton, November 1943

This paper provides developments by which the original fixed-bed Houdry process was adapted to produce basestock for aviation gasoline. Among the developments were the manufacturing of synthetic catalyst, production of isobutane and butylene for alkylation and catalytic treating of primary basestock.

How will the 100-octane aviation gasoline program affect post-war motor gasoline?
B. K. Brown and D. P. Barnard, December 1943

With the return of competition in cost, processes and raw materials, the authors of this article are of the opinion that: "As much as 100,000 barrels of 100-octane capacity will be shut down or diverted to other uses because of excessive operating costs and crude utilizations."

Bombs fall on Ploesti
March 1944

"For the Ploesti mission, every plant in each element was given a pinpoint and had to find it. There are no secondary targets." This quote—said Lieutenant B. O. Lisle during the annual meeting of the American Institute of Mining and Metallurgical Engineers—summed up the bombing of refining centers in Ploesti, Poland by Allied bombers. Refined fuels were crucial in aiding the war effort on both sides. Without oil/fuels, military operations could not be conducted.

Study of the effect of catalytic cracking on the post-war supply of motor gasolines, distillates and residual fuels
March 1944

Previous advances in refining technology have been slowly adopted. Necessity for military-grade gasolines brought catalytic cracking into refining without regard to other considerations. With the end of fighting, catalytic cracking capacity, the quality of its products, its ownership and its location will suddenly become factors in what the industry has to sell.

Use of the mass spectrometer in the routine analysis of refinery gas samples
J. G. Schaafsma, April 1944

This article provides a brief discussion on the theory and operation of the mass spectrometer and its performance when used to control and acid alkylation unit.

How to train plant personnel in fire prevention and fire fighting
A. W. Trusty, May 1944

Refining personnel is changing rapidly and many new personnel have never seen an oil fire. It is imperative that operators be familiar with the cause and nature of fires, along with the most efficient and quickest methods to combat them.

Influence of ozone on diesel engine performance
W. J. Armstrong and C. E. Thorp, June 1944

For several years, ozone has been suggested as an agent that might be of value in obtaining improvement in the thermal efficiency of internal-combustion engines. This paper describes various experiments to determine the influence of ozone on compression-ignition engine performance.

Chemicals from petroleum
H. D. Wilde, July 1944

The outstanding raw material used today for synthetic chemical production, especially from a volume standpoint, is butylene.

Time-saving computing instruments for spectroscopic analysis
T. D. Morgan and F. W. Crawford, September 1944

Chemical plants depend on rapid analytical methods as a guide to keep the plant onstream. Successful applications of spectroscopic methods to these analytical problems have shortened the time interval from sampling to completion of an analysis, saving a significant amount of workers' time.

Characteristics of the differential-type flowmeter and conditions affecting its operation
L. K. Spink, November 1944

This work not only tells what to do and what to avoid in considering flowmeter applications, but also cites the penalties in terms of percent error if certain rules are not observed.

Plastics from petroleum
B. H. Weil, January 1945

This article provides a look at the many types of plastics that are produced from petroleum oil. The article includes sections on terminology, history, raw materials and processing routes to produce plastics. From the article's introduction:

"Plastics today, are materials with which to conjure. Industrial designers have depicted sleek plastic-bodied cars with transparent plastic tops and windshields. Advertisements have shown the home of the future as a dwelling built of plastic-bonded plywood, replete with plastic equipment from bathtub to lighting. Newspaper accounts have dwelled upon the coming age of plastics in which almost every article of commerce will have plastics used in them. All this publicity has served to focus the spotlight of attention upon materials and products which, in appearance and use, have long been of interest and utility to the public and industry alike."

Fuels for high-speed diesel engines
V. A. Kalichevsky, April 1945

The original development of trucks and busses as an important transportation factor was based on the use of gasoline engines to supply motive power. This source of power has continued predominantly because availability of gasoline has kept pace with demand. However, a considerable amount of work has been carried out, leading towards the development of diesel engines on the basic presumption that they are less discriminating with respect to fuels.

Super compressibility of natural gas upon compressor performance
R. S. Ridgway, May 1945

There seems to be some tendency to ignore the effect of super compressibility upon compressor performance and to assume that discrepancies from this source can be neglected. It is the aim of this paper to point out the dangers of such a practice, to indicate the practical value of the proper treatment and to present the methods of calculation which recognize this effect.

The fluid catalytic cracking process– How it operates

May 1945

This article provides a step-by-step look at the fluid catalytic cracking process, including a colored diagram provided by the M. W. Kellogg Co.

Functions and fundamentals of temperature in refinery process control

D. M. Boyd, September 1945

Instrumentation is the control of a product by its physical properties. At present, only two properties—temperature and pressure—are being extensively used in refining. It is evident that many additional properties can and should be used, such as refractive index, absorption spectra and dielectric property.

It is the purpose of this article to trace the development of temperature process control and to provide several examples of problems encountered in the design and operation of a 100-octane gasoline plant, which requires more than 300 instruments.

Synthetic lubricants from ethylene condensations

H. Schildwachter, March 1946

The condensation of ethylene with coal-tar fractions can produce valuable lubricants. The viscosity of such synthetic oils can be further increased by treatment with silent electric discharges. These oils show good stability under heat, are free of asphalt and potential sludge bodies, and do not form tars during oxidation at 120°C, among several other benefits.

Disposal of refinery wastes

L. C. Burroughs, July 1946

Since its inception, the petroleum industry has been confronted with the problem of the proper disposal of the wastes produced from oil-refining processes. Two conditions dictate close study on the subject of waste: the pressing necessity of more economical operation and the fact that political bodies continue to demand more from industry in the protection of both surface and underground water supplies.

Design of instrument-air-supply system for the process industry

W. C. Ludi, October 1946

The purpose of this article is to outline present practice in the design of instrument-air-supply systems for process units. These systems are important in plants using automatic control instruments since continuous satisfactory performance is essential to the production of specification products and the maintenance of operator morale. Also included is a discussion of instrumentation air drying methods and systems, and notes on the principal design features desired in the mechanical equipment of instrument-air systems.

Fundamental requirements for safe arrangement of drains and vents

J. H. Johnson, June 1947

The primary functions of drain and vent systems on oil processing units are to provide a means of quickly and safely disposing of oil and gas in an emergency, and to provide a means for safely draining and venting various parts of a unit during operation. The article details the fundamentals of arranging drains and vents in a processing unit.

Maintenance of tubular heat exchangers

J. G. Housman, July 1947

The proper techniques regarding maintenance on tubular heat exchangers at Standard Oil Co.'s Whiting refinery are discussed.

Cracking sulfur stocks with natural catalyst

R. C. Davidson, September 1947

This article presents the characteristics of catalyst which have been poisoned by sulfur and the procedure prohibiting the decline in activity caused by cracking gasoils containing relatively large amounts of sulfur compounds.

Refinery building program is stupendous

L. J. Logan, October 1947

Facing a substantial increase in the demand for petroleum products over the new few years, the refining branch of the petroleum industry is confronted with the necessity for a refinery building program beyond any figure heretofore quoted.

Where does the sulfur go?

M. J. Fowle and R. D. Bent, November 1947

This paper presents the distribution of sulfur in products when processing sour crude by distillation, thermal viscosity, breaking, gasoil cracking and reforming; catalytic cracking; catalytic desulfurization; and chemical treating.

Flange design calculations

H. E. Lonngren, November 1947

The author presents new formulas for determining the flange thickness quickly, with an assurance of obtaining a predetermined and uniform stress distribution in the flange. The derivation of the new formulas is based on the present formulas in the ASME and ASME-API codes.

The aromatic adsorption index as a rapid method for approximating catalyst activity

W. W. Scheumann and A. R. Rescorla, December 1947

Control of catalytic cracking operations requires frequent measurement of catalyst activity. The aromatic adsorption index is based on the ability of a cracking catalyst selectively to adsorb aromatic hydrocarbon from a hydrocarbon mixture.

Straight-line chart determination of absorber extraction efficiency

E. W. Ragatz, February 1948

The recently proposed straight-line chart method of absorber analysis has been broadened and refined with the resultant development of a highly significant overall performance factor. This factor has been given the designation of Extraction Efficiency and expresses the ratio (in terms of percent) of the theoretical minimum to actual lean oil rate required to affect a 95% butane recovery at any absorber operation. Application of this factor to a wide range of commercial units indicates the possibility of markedly improving the effectiveness of present day high-pressure absorbers.

New weapon of science—Radioactive isotopes
May 1948

A research project to unlock the still unknown secrets that make the conversion of coal and natural gas into gasoline possible is underway by Gulf Oil Corp. Radioactive isotopes are being applied to the study since the basic nature of the chemical reaction of the process remains a mystery. Sufficient technical knowledge exists to proceed with commercial production; however, the ultimate possibilities of the reaction cannot be judged until what happens in the reaction is better understood.

By sampling the presence of radioactive atoms in various stages of the process by a Geiger counter, the researchers hope to trace the course of carbon atoms and blueprint the entire reaction.

Industrial engineering in refinery maintenance planning
W. H. Reynolds, August 1948

The intention of this article is to emphasize the importance of providing basic tools for the analysis and investigation of all plant procedures. A "job order" system with resultant cost segregation and accumulation is offered as a basis for improving plant routines.

Designing for efficiency—Gas compressor systems
T. G. Hicks, December 1948

Gas compression plays a necessary part in operations throughout the refining, natural gasoline and petrochemical processing plants. Whether the gas handled is from a field vacuum gathering system, is being moved through a long-distance pipeline or is evolved from a conversion reaction in a processing facility, the problems of compressor installation and station design are much the same. Certain utilities must be provided, piping must be worked out to accommodate the process operating conditions, adequate foundations must be designed and maintenance requirements must be considered, among other factors.

Nuclear fission as a source of competitive energy
T. R. Hogness, April 1949

Currently, there is no such thing as atomic power, in the sense of the strict definition of power. However, surely, we shall have this power and in the not too distant future. The principles are known, tentative designs for power reactors have been made, and many necessary preliminary experiments are under way. With our faith in the ability to solve a very difficult problem, feasibility is fast growing into certainty.

Analytical instruments in automatic control systems
N. Gildersleeve, June 1949

There is a significant trend in process plant instrumentation toward the more general use of analysis-type instruments for the direct control of operating variables. The development of satisfactory instrumentation for the automatic control of the physical variables—temperature, pressure, flow, liquid level, etc.—resulted in great improvement in process plant operation, so now instruments capable of analyzing process stream compositions will bring about smoother operation of process equipment and a higher percentage of on-specification production.

Drainage time for bubble cap columns
J. L. Huitt, W. C. Ziegenhain, F. C. Fowler and
R. L. Huntington, November 1949

The time required for a fractionating column to drain after it has been taken offline is a factor that enters the routine operation of many plants employing distillation. However, literature reports little, if any, experimental data on this operation and no method of calculating this drainage time. This article addresses this challenge.

Power plants for modern refineries
T. G. Hicks, December 1949

Power plants serving today's refining, natural gasoline and petrochemical plants have come a long way since the well-known oil field boiler days. No longer is steam generation the only function of the refinery power plant. Electricity in large quantities becomes more necessary every time a new production operation is introduced. With the decrease in availability of byproduct fuels, refinery power plant efficiency takes on a new importance. To achieve low cost production, today's refinery designer must strive for the optimum balance obtainable between process and power generating facilities. Obtaining such a balance is not readily done because it involves a multitude of factors. **HP**

The First FCC Changes the World
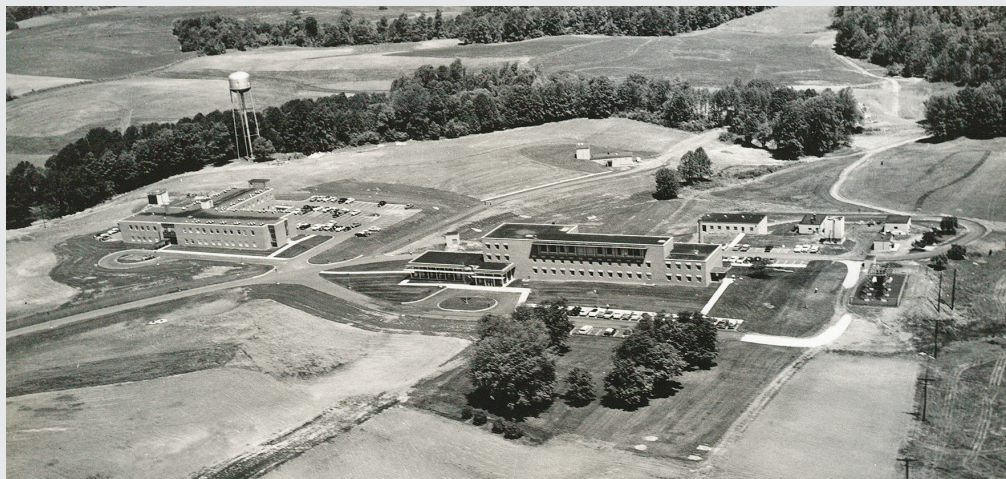
In 1942, Grace's Curtis Bay manufacturing plant shipped the first fluid cracking (FCC) catalyst for petroleum refining to the world's first commercial FCC unit in Baton Rouge, LA. The primary goal was to make high-quality aviation fuel for the Allies effort in WWII, influencing the outcome of the war. By 1945, there were more than 34 FCC units in operation-all supplied by Grace-eventually making other conversion processes obsolete. Over its 80-year history, FCC units have been reconfigured and expanded to produce a wider variety of fuels, taking advantage of the extreme degree of flexibility enabled by this revolutionary system. The FCC is now one of the principal conversion units in modern petroleum refining.

LEGACY OF INNOVATION

FCC capacity increased after the war to supply motor fuels and a technology revolution began. In the 1960s, FCC zeolite innovation increased gasoline yields and in the 1980s, innovation in additives enhanced propylene yields and octane while providing solutions for refiners to comply with increasing environmental regulations. And, into the new century, FCC catalysts are increasingly being used to tackle challenges in resid processing and metals passivation.

Like the FCC unit, Grace's FCC catalysts are extremely flexible, and help refineries stay competitive in various ways. In addition to custom catalyst design for all yield objectives, Grace is known for industry leading technical service, and continually advancing FCC catalyst innovation to improve product performance and create value. And as the world moves to newer, and more diverse sources of energy and chemical products, Grace's team is working to adapt our FCC catalysts to enable refiners to solve evolving challenges associated with petrochemical precursor production, feedstock diversity, new environmental limits, and coprocessing of bio-based feedstocks.

Since its inception, Grace has led the way in creating value for refiners by processing more or broadening feed profiles using innovative technology. Over the decades, Grace built an impressive FCC manufacturing network, which solidified its reputation as the world's leading supplier of FCC catalysts and additives. And, with laboratory and manufacturing sites on multiple continents supplying units in more than 60 countries, Grace successfully brings next generation technologies through the pipeline from R&D to wide commercial use.

As you might expect from the pioneer in FCC catalysts, Grace was the first catalyst company to provide technical services to the refining industry. Today, world-class technical service and specialized evaluation tools help refiners create opportunities from the challenges they face, ensuring they capture the most value from the operation of their FCC unit.

WORKING ON WHAT'S NEXT

So, what's next for Grace and the FCC unit? The next major advancement in refining is already underway. The flexible FCC unit is being deployed more creatively to increase propylene supply and help support our industry's sustainability ambitions. In many ways, the FCC's role in the modern refinery is being re-invented to reduce emissions and waste, repurpose to cleaner fuels and petrochemical production, and recycle spent catalyst and other materials.

The energy transition is as ripe of an opportunity for innovation as the early days when the invention of fluid catalytic cracking literally changed the world. From co-processing biofuels to reducing emissions, Grace is investing the people, research, and technology it will take to pursue a more sustainable energy future.

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Polymer science, catalytic cracking, petrochemicals and EPC

WALDO SEMON
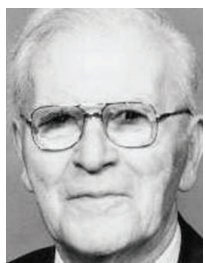
Waldo Semon was an American chemist whose detour with assigned laboratory research at B. F. Goodrich led to the development of vinyl—the second best-selling plastic in the world. Dr. Semon's original research project was to coat metal with synthetic rubber. However, having exhausted his possibilities with rubber, he began experimenting with synthetic polymers, including polyvinyl chloride (PVC). Dr. Semon heated the stiff polymer in a high boiling solvent, obtaining a jelly-like substance that was elastic but not adhesive. PVC was more durable than crude rubber and Semon continued experimenting with it until he finally succeeded, in his first breakthrough, in plasticizing the substance and making it highly resilient. In his second breakthrough, he succeeded in making the material moldable into different shapes, giving the world its second-most employed plastic. Goodrich commercialized this product under the trademark Koroseal,[1] making shock-absorber seals, electric-wire insulation and coated-cloth products.

Semon's success with vinyl did not deter his original research. By 1934, he had invented over 100 methods of affixing synthetic rubber to metal. He continued to lead teams of researchers to invent other families of plastics, which earned him 116 U.S. patents[2] and the Charles Goodyear medal in 1944.[3] Throughout his career, he was known for his devotion and support of science education in schools.

FREDERIC STANLEY KIPPING

Frederic Stanley Kipping was a British chemist whose pioneering work in the chemistry of silicones formed the basis of 40 yr of continued research at the interface of organic and inorganic chemistry and the commercial development and application of silicones. He was the chief demonstrator in chemistry at the City and Guilds of London Institute and later became a professor of chemistry at University College, Nottingham. Kipping's research on optically active compounds resulted in his interest and study of organic silicon compounds at Nottingham during the early 1900s. His work was published in a series of 51 journal papers and formed the basis for pioneering research that led to the development of synthetic rubber and silicone-based industries.[4] With exceptional water resistance, high-temperature stability silicones found a variety of early applications as synthetic rubber, hydrophobic coatings, greases and lubricants.[5]

JAMES FRANKLIN HYDE

Dr. James Franklin Hyde, an American chemist and inventor, is credited with the commercialization of the silicone industry. His research combines organic and inorganic chemistry and the advantages of plastics and glass to create silicones, as an advanced commercial product. Glass is silicon-based, temperature and moisture-resistant, chemically inert and dielectric, while plastics are carbon-based, strong, durable and moldable. Dr. Hyde's silicone resins exhibit a combination of resistance to water, ultraviolet light, microbial growth and thermal conductivity, while being strong and stable. The substance instantly became applicable in a variety of applications like greases, lubricants, insulators, sealants, waxes and rubbers, among others.

Dr. Hyde's research built upon Dr. Eugene Sullivan's radical idea of producing a hybrid material by combining the advantages of glass with those of organic plastics to create an array of organosilicon compounds. Dr. Hyde recognized the commercial importance of some of Kipping's observations and applied them to forge his hybrid technology. His work led to the formation of Dow Corning, an alliance between the Dow Chemical Co. and Corning Glass Works that was specifically created to produce silicone products in 1943.[6] At Dow Corning, Dr. Hyde led numerous innovations throughout the mid-20th century, with applications in industries such as automobiles, construction, aerospace, cookware and pharmaceuticals.

Besides silicone compounds, his other notable contributions include a flame hydrolysis method of making fused silica, a high-quality glass employed initially in telescopes and later used in aeronautics, advanced telecommunications, and computer chips. Dr. Hyde was honored with the Perkin Medal, finished his career credited with around 120 patents and was inducted into the National Inventors Hall of Fame.[7]

VLADIMIR IPATIEFF

Vladimir Nikolayevich Ipatieff was a Russian and American chemist who made significant contributions to the field of petroleum chemistry and catalysis. Ipatieff made the important discovery that chemical reactions were influenced by the walls of the container in which they were taking place. One of his noted reaction discoveries was when he found that alcohol flowing through a heated iron reaction coil caused primary, secondary and tertiary alcohols to be dehydrogenated producing aldehydes, ketones and alkenes, respectively. This reaction was absent when the same alcohol was flowing through a quartz tube. He called this phenomenon 'contact reactions,' which we now know as heterogeneous catalysis.

Ipatieff discovered that catalyst efficiency could be enhanced by dispersing catalyst particles on inert support and including small amounts of zinc or copper on the support. Most industrial reactions employ catalysts dispersed on support, along with additives or promoters. He also demonstrated that γ-alumina can function as an effective dehydration catalyst, especially in ethanol to ethylene reactions. This discovery led to the development of methods for converting ethanol to alkenes, such as butadiene, which is used in the manufacture of rubber. In the 1940s, these processes were used in the commercial production of butadiene and are still being used today.

Ipatieff made another seminal innovation in chemistry by developing high-pressure autoclaves, often referred to as 'Ipatieff bombs.'[8] Ipatieff used these high-pressure autoclaves to synthesize commodity chemicals in processes that were significantly less expensive than traditional methods. He published more than 300 research papers and received more than 200 patents.[9] Ipateiff's work at UOP—in collaboration with Herman Pines, especially their breakthrough in fuel chemistry—is his most significant contribution to petroleum chemistry and refining.

HERMAN PINES

Herman Pines was a Polish-American chemist whose work in understanding the chemistry of hydrocarbons and catalysis laid the groundwork for producing high-octane fuels. Paraffins were considered inert substances, with little or no reaction affinity. His research led to the development of processes for paraffin isomerization, aromatic alkylation and base-catalyzed organic reactions. Pines developed a method for catalytic conversion of paraffins, such as n-butane to isobutane. He also demonstrated low temperatures catalysis by successfully reacting isobutane with olefins in the presence of sulfuric acid as a catalyst at low temperatures. The combination of isomerization and alkylation proved to be the breakthrough in developing high-octane fuel initially for aviation and later commercialization in 1941.[10]

Pines joined UOP in 1930, which began his long collaboration with Dr. Vladimir Ipatieff.[11] They worked on understanding complex reactions affected by temperature, acid concentration and ratio of acid relative to other compounds. Pines used pure hydrocarbons in his research instead of petroleum fractions to understand mechanisms for dehydration of alcohols on alumina, aromatization of alkanes, hydrogen transfer reactions in aromatic hydrocarbons and several other acid and base catalyzed hydrogenation, aromatization and dehydrogenation reactions. Pines' research team studied a variety of transformations, including polymerization, alkylation, cyclization, additions, eliminations and hydride transfer reactions. Upon leaving UOP in 1953, he continued working on understanding and describing hydrocarbon reaction mechanisms and heterogenous catalysis at Northwestern University as the Ipatieff Professor. He published nearly 265 scientific papers and received 145 patents.[10]

VLADIMIR HAENSEL

Vladimir Haensel was an American chemical engineer most known for his invention of the Platforming process—a platinum catalyzed process for reforming hydrocarbons into gasoline. In 1947, he demonstrated that 0.01 platinum on alumina can be used as a stable, active and effective catalyst with long life and high in situ regeneration efficiency.[12] Platinum on alumina functioned as a dual-functional catalyst, where platinum provides excellent hydrogenation and dehydrogenation activity and the unsaturated hydrocarbons formed could be isomerized to rings on the acidic alumina. Associated major process advantages were a high yield of hydrogen, a valuable and environmentally friendly product aiding sulfur removal and high yield of aromatics, valuable for downstream plastics and petrochemicals industries.

Haensel's method for producing high-octane fuel eliminated tetraethyl lead as an anti-knock additive; made transportation fuel efficient, cheaper and environment friendly; and replaced toxic coal tar processing by generating an aromatics pool for the plastics industry. Haensel is also known for the program he established as Director of Research at UOP,[13] which led to the development of catalytic converters for automobiles.

J. R. WHINFIELD AND J. T. DICKSON

John Rex Whinfield (left) and James Tennant Dickson (right) investigated thermoplastic polyesters while working in the laboratories of the Calico Printers' Association Ltd. from 1939–1941.[14] They produced and patented the first polyester fiber in 1941, named Terylene, which equaled or even surpassed the toughness and resilience of nylon.

In the late 1930s, there was significant emphasis on finding an alternative to Carother's aliphatic nylon fiber. Aromatic polyesters had remained largely unexplored during this time. By 1939, there was enough research evidence to support micro crystallinity as essential for the formation of strong synthetic fibers. The need for molecular symmetry in forming microcrystalline

polymers formed the basis for Whinfield and Dickson's research approach in using an aromatic polymer with a sufficiently high melting temperature for the manufacturing of synthetic fiber. Whinfield and Dickson discovered a method to condense terephthalic acid and ethylene glycol to yield a new polymer that could be drawn into fibers. Their patent was published in 1946.[15]

Whinfield joined Imperial Chemical Industries (ICI) in 1947 and ICI manufactured Terylene, while rival Dupont produced their own version of the polyester fiber commercialized as Dacron.[15]

CHARLES A. STONE AND EDWIN S. WEBSTER

Charles A. Stone and Edwin S. Webster—friends, electrical engineers and MIT classmates of 1888—founded Massachusetts Electrical Engineering Company, one of America's first engineering consulting firms. The company was renamed Stone & Webster and grew to an engineering services company providing engineering, construction, environmental, and plant operation and maintenance services.

By the early 1950s, the company was involved with several noteworthy oil and gas, petrochemical and power generation projects, including 27 hydroelectric power generation proj-

ects and interstate gas pipelines in the U.S.[16] The company also worked on various projects in chemical and plastics processing in the U.S., Canada, Japan and other countries serving the growing demand for plastics. Their efforts to standardize designs in areas of proven success and building project teams were successfully applied to address problems that developed in the energy supply sector in the mid- to late-1960s. These were used in the design of synthetic natural gas plants, an LNG distribution center, and demonstration projects in coal and oil gasification.

Stone & Webster was acquired and integrated into The Shaw Group in 2000. In 2012, the energy and chemical business, and process technologies and associated oil and gas engineering capabilities of The Shaw group were acquired by Technip.[16] Today, the company is known as Technip Energies. **HP**

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Utilize heavy-duty cable tray systems to improve cable tray designs

This article presents a novel design concept that utilizes a heavy-duty cable tray system to optimize cable tray design, procurement and construction. Typically, cable tray designs follow the examples mentioned in National Electrical Manufacturers Association (NEMA) standards. In Saudi Aramco's Tanajib Gas Plant project, a full report for the cable tray and structural steel design—containing detailed design calculations, shop tests witnessed by an outside inspection agency and simulations prepared by Wescosa—was conducted to prove the compliance of the heavy-duty cable tray system with all applicable standard requirements.

One of the difficulties that many oil and gas projects face is the demand for power, which leads to a significant number of cables. In Saudi Aramco projects, the preferred installation method for cables is utilizing aboveground cable trays to enhance the safety, reliability and maintenance requirements. Therefore, aluminum cable trays are the ideal option for projects that require properly designed pipe rack and cable tray supports.

Utilizing heavy-duty cable tray systems will significantly optimize the quantity of supports required for the cable tray without affecting the quality, reliability and safety of the facility. This will also eliminate the difficulties of the design and installation, especially in congested areas where multiple curves and levels coincide. Moreover, this will improve the project schedule related to material delivery and installation.

The NEMA VE 2 standard addresses the shipping, handling, storing and installation of cable tray systems. This article will demonstrate the comparison between the typical NEMA VE 2 design and the improved design according to the manufacturer's recommendation, which utilizes the application of a heavy-duty cable tray system based on horizontal 6-m cable trays with heavy-duty joint connectors and heavy-duty expansion joint connectors. In addition, the system includes heavy-duty horizontal bend fittings, heavy-duty horizontal tee fittings and heavy-duty horizontal cross fittings.

NEMA VE 2 design. The following details NEMA VE 2 requirements:

- The expansion joint connector should have two supports located within 600 mm (2 ft) on each side.
- The horizontal bend fitting should have one support located in the center of the fitting and two supports within 600 mm (2 ft) of each fitting's edge.
- The horizontal cross fitting should have four supports under each side rail and four supports within 600 mm (2 ft) of each fitting's edge.
- The horizontal tee fitting should have three supports under each

TABLE 1. Horizontal bend fitting—Nominal data

Safe working load (SWL)	Total length of mid-line fitting, L_m	Width of cable tray fitting, w	Load Q	Load $Q_{1.7}$
149 kg/m	3,571.8 mm (3.5718 m)	900 mm (0.9 m)	532.2 kg	907.74 kg

TABLE 2. Horizontal bend fitting—Mid-span deflection results

	Mid-span deflection				
	Point R	Point T	Average, (R+T)/2	Required, (L_m/100)	Remarks
At Load Q	13.63 mm	41.99 mm	27.81 mm	≤ 35.7 mm (no damage)	Passed
At Load $Q_{1.7}$	15.78 mm	52.62 mm	34.2 mm	No collapse	Passed

TABLE 3. Horizontal bend fitting—Transverse deflection results

	Transverse deflection			
	Point S	Transverse, S-average	Required, (w)/20	Remarks
At Load Q	28.48 mm	0.67 mm	≤ 45 mm (no damage)	Passed
At Load $Q_{1.7}$	35.52 mm	1.32 mm	No collapse	Passed

side rail and three supports within 600 mm (2 ft) of each fitting's edge.

Improved manufacturer's design. The following details the requirements of the improved design according to the manufacturer:

- The expansion joint connector should have one support located within a quarter point of the expansion joint connector.
- The horizontal bend fitting should have two supports within 600 mm (2 ft) of each fitting's edge.
- The horizontal cross fitting should have four supports within 600 mm (2 ft) of each fitting's edge.
- The horizontal tee fitting should have three supports within 600 mm (2 ft) of each fitting's edge.

Tests and reports. The cable tray manufacturer for the Tanajib Gas Plant project submitted a full report ensuring and validating the compliance of the improved manufacturer design with NEMA, International Electrotechnical Commission (IEC) and Saudi Aramco standards. As per paragraphs 9.4 and 9.10 of Saudi Aramco's SAES-P-104 standard, the following criteria, including safe working load (SWL) recommendations, were followed:

- **9.4.** The working load for cable trays should consist of the weight of the cables (or tubing, etc.) including future additions (if required), plus a concentrated static load of 90 kg at the center of the span. The working load should not exceed the rated load capacity of the cable tray defined in NEMA VE 1 or NEMA FG 1 (destruction load divided by a safety factor of 1.5).
- **9.10.** Deflection of the cable tray system (several sections spliced together as a continuous beam), when loaded to the working load as defined in paragraph 9.4, excluding the concentrated static load, should not exceed L/100 (L = span length).

Actual load tests. To verify that the heavy-duty cable tray system adhered to the mandated required loading capacity as per paragraph 9.4 of this Saudi Aramco standard, all fittings and multi-span straight cable tray sections were tested locally in the manufacturer's shop and witnessed by a third-party agency as per IEC 61537 clauses 10.2, 10.3 and 10.7, and NEMA VE 1 Clause 5.2. The following are details from these tests.

Horizontal bend fitting. The horizontal bend fitting was assembled as per

the improved manufacturer's design, using the recommended splicing device, and mounted at the supports. The test procedure followed IEC 61537 Clause 10.2. The horizontal bend fitting nominal data used for the actual load tests are shown in **TABLE 1.** Load Q is the uniform distributed load applied on the fitting (SWL × L_m). Load $Q_{1.7}$ is the uniform distributed load applied on the fitting, with a safety factor of 1.7 (SWL × L_m × 1.7).

It was observed that the practical mid-span deflection at Load Q met the required acceptance criteria of (< L_m/100). Moreover, the sample sustained at Load $Q_{1.7}$ without collapse. Therefore, the testing result for mid-span deflection passed. Detailed values are shown in **TABLE 2.**

It was observed that the transverse deflection—which is the vertical deflection across the width of the base area, omitting the longitudinal deflection—when mounted horizontally, met the required acceptance criteria of (< (w)/20). Therefore, the testing result for transverse deflection passed. Detailed values are shown in **TABLE 3.**

Horizontal tee fitting. The horizontal tee fitting was assembled as per the improved manufacturer's design, using the recommended splicing device, and mounted at the supports. The test procedure followed IEC 61537 Clause 10.2. The horizontal tee fitting nominal data used for the actual load tests are detailed in **TABLE 4.** Load Q is the uniform distributed load applied on the fitting (SWL × L_m). Load $Q_{1.7}$ is the uniform distributed load applied on the fitting, with a safety factor of 1.7 (SWL × L_m × 1.7).

It was observed that the practical mid-span deflection at Load Q met the required acceptance criteria of (< L_m/100). Moreover, the sample sustained at Load $Q_{1.7}$ without collapse. Therefore, the testing result for mid-span deflection passed. Detailed values are shown in **TABLE 5.**

It was observed that the transverse deflection—which is the vertical deflection across the width of the base area, omitting the longitudinal deflection—when mounted horizontally, met the required acceptance criteria of (<distRT/20). Therefore, the testing result for transverse deflection passed. Detailed values are shown in **TABLE 6.**

Horizontal cross fitting. The horizontal cross fitting was assembled as per the improved manufacturer's design, us-

TABLE 4. Horizontal tee fitting—Nominal data

SWL	Total length of mid-line fitting, L_m	Distance, Point R to Point T (distRT)	Load Q	Load $Q_{1.7}$
149 kg/m	6,236.1 mm (6.2361 m)	1,405.4 mm (1.4054 m)	929.18 kg	1,579.6 kg

TABLE 5. Horizontal tee fitting—Mid-span deflection results

	Mid-span deflection				
	Point R	Point T	Average, (R+T)/2	Required, (L_m/100)	Remarks
At Load Q	14.11 mm	9.7 mm	11.91 mm	≤ 62.3 mm (no damage)	Passed
At Load $Q_{1.7}$	20.7 mm	14.82 mm	17.76 mm	No collapse	Passed

TABLE 6. Horizontal tee fitting—Transverse deflection results

	Transverse deflection			
	Point S	Transverse, S-average	Required, (distRT)/20	Remarks
At Load Q	33.69 mm	22.05 mm	≤ 70.27 mm (no damage)	Passed
At Load $Q_{1.7}$	51.31 mm	33.55 mm	No collapse	Passed

TABLE 7. Horizontal cross fitting—Nominal data

SWL	Total length of mid-line fitting, L_m	Distance, Point R to Point T (distRT)	Load Q	Load $Q_{1.7}$
149 kg/m	8,314.8 mm (8.3148 m)	2,068 mm (2.068 m)	1,238.9 kg	2,106.15 kg

ing the recommended splicing device, and mounted at the supports. The test procedure followed IEC 61537 Clause 10.2. The horizontal cross fitting nominal data used for the actual load tests are shown in **TABLE 7.** Load Q is the uniform distributed load applied on the fitting (SWL × L_m). Load $Q_{1.7}$ is the uniform distributed load applied on the fitting, with a safety factor of 1.7 (SWL × L_m × 1.7).

It was observed that the practical mid-span deflection at Load Q met the required acceptance criteria of ($<L_m/100$). Moreover, the sample sustained at Load $Q_{1.7}$ without collapse. Therefore, the testing result for mid-span deflection passed. Detailed values are shown in **TABLE 8.**

It was observed that the transverse deflection—which is the vertical deflection across the width of the base area, omitting the longitudinal deflection—when mounted horizontally, met the required acceptance criteria of ($<distRT/20$). Therefore, the testing result for transverse deflection passed. Detailed values are shown in **TABLE 9.**

Multi-span straight cable trays. The multi-span straight cable trays (five spans) were assembled as per the improved manufacturer's design, using the recommended splicing device, and mounted at the supports. The nominal data included the following:
- Rated load: 149 kg/m at 6-m span
- Maximum mid-span deflection ($L_m/100$): 60 mm
- Total test load: 4,470 kg.

The test procedure followed IEC 61537 Clause 10.3 and NEMA VE 1 Clause 5.2. The total test load is defined by Eq. 1:

$$\text{Total test load} = 5 \text{ spans} \times 149 \text{ kg/m per span} = 5 \times 149 \text{ kg/m} \times 6 \text{ m} = 4{,}470 \text{ kg} \qquad (1)$$

It was observed that the average deflection span at 100% total test load met the required acceptance criteria of ($L_m/100$). Therefore, the testing result for average deflection span passed. Detailed values are shown in **TABLE 10.**

Simulation validation. The design was validated by simulating several recommended tests and utilizing proprietary software that can validate the actual test performed to be installed in an industrial environment. The results of the validation exercise have been reviewed by Saudi Aramco's engineering consultation com-

mittee, including civil, structural and electrical consultants. The simulations performed included the following:
- Static structural analysis
- Thermal structural analysis at maximum temperature
- Thermal structural analysis at minimum temperature.

All simulations were successful and met the required acceptance criteria.

Recommendations and limitations. As a result of the manufacturer's report, a set of recommendations and limitations was developed to ensure the design capability and the installation integrity. These recommendations and limitations included the following:
- The heavy-duty cable tray system can be applied to any length of trays, with proper testing and validation.
- Installation should be limited to horizontal cable tray runs. Vertical cable tray runs should be installed as per NEMA VE 2 requirements.
- Fittings should not be installed immediately before or after a heavy-duty expansion plate.
- Only three types of fittings are considered: horizontal bend fittings, horizontal cross fittings and horizontal tee fittings.
- Cable tray fitting supports should be located within 600 mm of the cable tray fitting's end.

- Cable tray supports should be located within a quarter span of all straight cable trays adjacent to the cable tray fitting.

Takeaway. This article has demonstrated an improved design for cable tray systems by utilizing the heavy-duty cable tray system that will enhance the design and installation of the structural steel and cable tray system. Concerning the design, the heavy-duty system eliminates the design complexity (especially in congested areas where multiple curves and levels coincide) that affects maintenance requirements. In addition, the heavy-duty cable tray system reduces the quantity of material needed for the structural steel, thus improving the schedule of the installation. For this case study, applying the heavy-duty cable tray system in the Tanajib Gas Plant project eliminated more than 15,000 supports of approximately 270 km of cable trays. **HP**

MOHAMMED ALHAMAIDI works as a Project Engineer for Saudi Aramco. He has more than 8 yr of experience in project management and working with electrical equipment. He earned a BSc degree in electronic and electrical engineering.

MOHAMMAD MULLA works for Saudi Aramco. He is a certified PMP with more than 10 yr of experience in managing large- and medium-scale projects in the oil and gas industry. He earned a Bch degree in computer engineering.

TABLE 8. Horizontal cross fitting—Mid-span deflection results

			Mid-span deflection		
	Point R	Point T	Average, (R+T)/2	Required, ($L_m/100$)	Remarks
At Load Q	9.74 mm	8.59 mm	9.17 mm	≤ 83.1 mm (no damage)	Passed
At Load $Q_{1.7}$	17.07 mm	16.26 mm	16.67 mm	No collapse	Passed

TABLE 9. Horizontal cross fitting—Transverse deflection results

		Transverse deflection		
	Point S	Transverse, S-average	Required, (distRT)/20	Remarks
At Load Q	58 mm	48.83 mm	≤ 103.4 mm (no damage)	Passed
At Load $Q_{1.7}$	93.87 mm	77.2 mm	No collapse	Passed

TABLE 10. Multi-span straight cable trays—Average deflection span results

Total test load	Average deflection span 1, end	Average deflection span 2	Average deflection span 3, center	Average deflection span 4	Average deflection span 5, end
100%	45.88 mm	14.01 mm	26.3 mm	11.42 mm	53.94 mm

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Cleaning mud oil incineration offgases

The sustainable management of petroleum exploration and refining requires appropriate treatment and disposal of the oily waste generated. One common method for the disposal of hazardous oily sludge or mud oil is incineration, typically using a rotary kiln. However, mud incineration produces gas containing a high level of acid and particulate matter that needs to be removed before the gas can be released to the atmosphere. This is usually accomplished using a scrubber and a baghouse. However, one complicating factor is that the temperature of the gas exiting the kiln is 980°C–1,200°C (1,800°F–2,200°F). The scrubber must be able to cope with such high inlet temperatures.

A proprietary reverse jet scrubber technology[a] is a unique acid absorption and particulate removal system that can simultaneously quench and subcool the gas, and that can handle these very hot temperatures when fitted with a patented weir bowl technology (**FIG. 1**). The weir bowl can be attached to the top of the inlet barrel of the scrubber, enabling the scrubber to manage inlet gas temperatures up to 1,200°C (2,200°F). The bowl distributes a continuous stream of liquid that overflows a weir. This stream creates a thin protective liquid coating over the inner surface of the inlet barrel, thus preventing it from coming into direct contact with the hot gas and extending the life of the scrubber in this hot, corrosive environment.

The proprietary reverse jet scrubbers have been used effectively in several incineration applications across industries due to their ability to not only scrub acid gas, but also to quench extremely hot incinerator effluent streams and to simultaneously achieve substantial particulate removal in
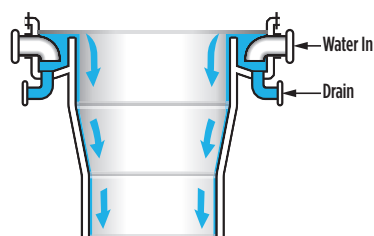

FIG. 1. The weir bowl for the proprietary reverse jet scrubber[a].
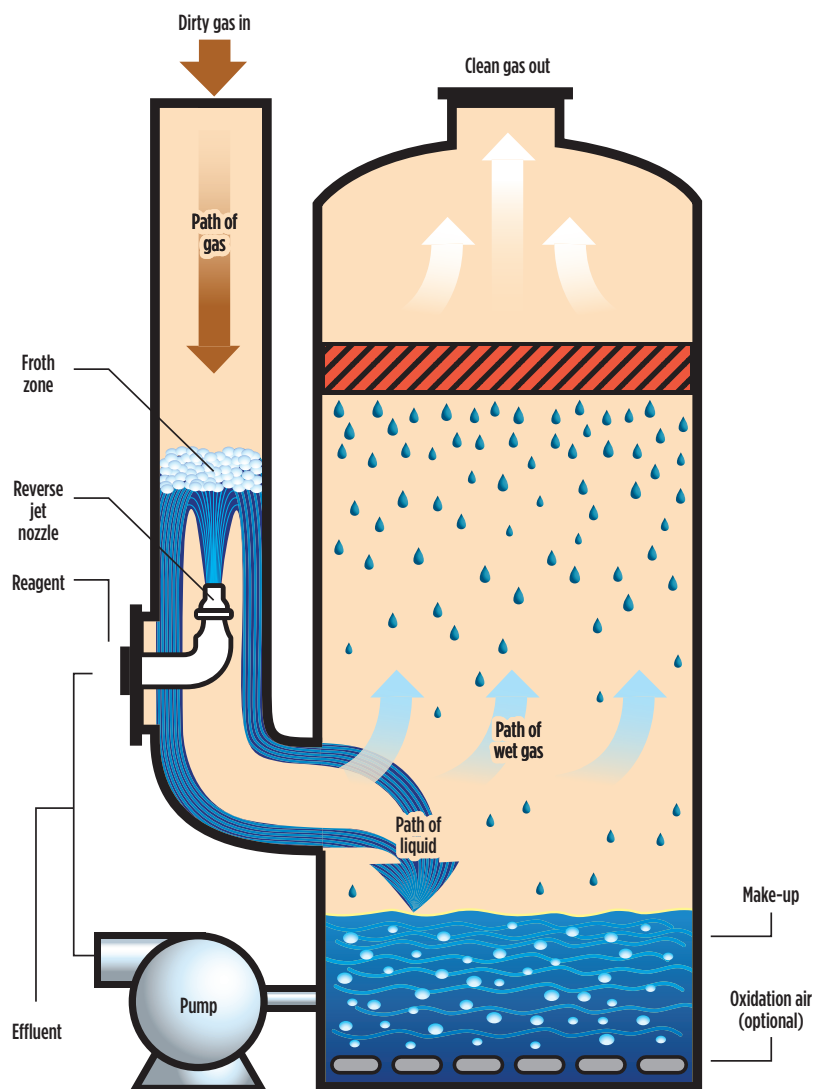

FIG. 2. View of the proprietary reverse jet scrubber system[a].

a single vessel. Developed in the 1970s, more than 400 of these versatile reverse jet scrubbers are in use around the world to treat emissions generated in a wide range of industrial processes with many of these systems in operation for more than 20 yr.

The proprietary reverse jet scrubber consists of an inlet barrel in which a reagent solution is injected countercurrent to the gas flow through very large open-bore spray nozzles (**FIG. 2**). A standing wave of highly turbulent flow—called the "froth zone"—is created at the point where the liquid is reversed by the gas. The froth zone produces a very high rate of liquid surface renewal, efficiently quenches the gas to the adiabatic saturation temperature, absorbs acids such as sulfur dioxide (SO_2) and efficiently removes particulate matter. After contacting the gas with the liquid reagent, the gas-liquid mixture enters a disengagement vessel where the liquid drops to the sump of the vessel and the gas exits the vessel through a demisting device.

There are no moving parts or narrow passages that could restrict gas flow, which prevents plugging issues. The required maintenance and operator attendance is minimal and these tasks can be handled during any scheduled turnaround of the refinery.

Mud incineration offgas treatment case study.

The following reviews a case study regarding SO_2 and particulate removal.

SO_2 removal. A refiner had installed a semi-dry lime scrubber and a baghouse for an existing mud incinerator to reduce SO_2 and particulate emissions (**FIG. 3A**). While the semi-dry lime scrubber was able to attain an SO_2 removal efficiency of approximately 90%, the plant needed to further reduce SO_2 to achieve required levels below 20 ppm. To solve this issue, the refinery installed the proprietary reverse jet scrubber downstream of the bag filter (**FIG. 3B**). The objective was to have a highly efficient system that would also be simple to operate, as only two operators were available at a time and the scrubber was sited a long way from the plant.

The flowrate of the incoming gas varied from 10,000 Nm^3/hr–12,000 Nm^3/hr. Although the proprietary reverse jet scrubber can be designed to handle much higher incinerator temperatures, in this instance, a pre-existing quench tower upstream of the scrubber meant that the inlet gas temperature to this 1.8-m-diameter scrubber vessel was approximately 150°C (302°F). The acid content on entry of the gas was roughly 2,000 ppm SO_2, which had to be reduced to below 20 ppm.

At the startup of the jet scrubber, two test runs were conducted. The first run had 1,700 ppm SO_2 coming into the scrubber with the incinerator offgas and measured less than 7 ppm SO_2 on exit. The second run recorded 1,500 ppm SO_2 on entry, with no SO_2 detected on exit (**TABLE 1**).

Particulate removal. The proprietary reverse jet scrubber is also capable of efficient particulate removal from mud incinerator offgases. Particulate removal depends on two things: the gas-side pressure drop and the particulate size. **FIG. 4** shows the relationship between the two and the resulting removal efficiency. The removal efficiency of the particulate depends on the particle size distribution.

In the refinery example, the gas leaving the bag filter still contained a certain

TABLE 1. SO_2 removal efficiency of the proprietary reverse jet scrubber system[a] during startup test runs

Test Run 1	Inlet	Outlet
Gas pressure drop, mmWC	200	
pH of the liquid	7–8	
SO_2, ppm	1,700	< 7
Test Run 1	**Inlet**	**Outlet**
Gas pressure drop, mmWC	200	
pH of the liquid	7–8	
SO_2, ppm	1,500	< 1

TABLE 2. Refinery inlet conditions to the proprietary reverse jet scrubber[a]

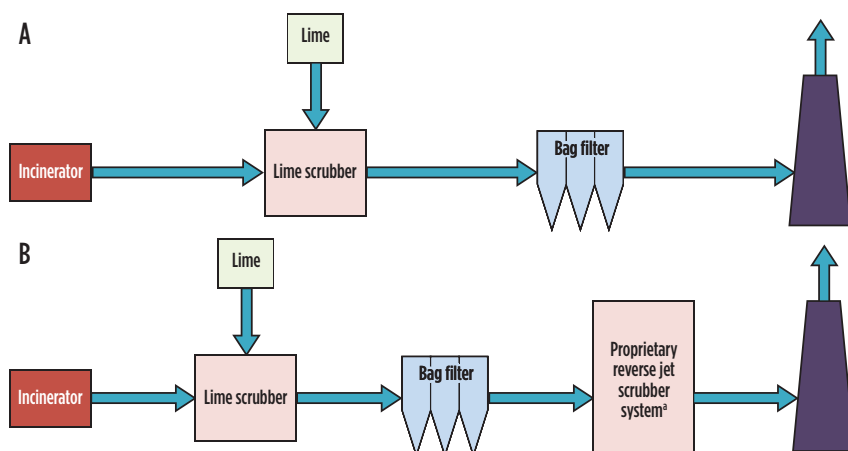| Inlet condition	Normal	Maximum
Flue gas flowrate, Nm^3/hr	10,000	12,000
Flue gas temperature, °C	130–150	150
Flue gas pressure, kg/cm^2 (G)	-0.04	-0.04
Barometric pressure, kPa	101.325	101.325
Flue gas composition, vol%		
Nitrogen	Balance	Balance
Oxygen	11	11
Water	10	10
SO_2	0.2	0.2
Sulfur trioxide (assumed)	0	0

FIG. 3. Typical scrubbing/baghouse flow diagram downstream of a mud incinerator (A) vs. the integration of the proprietary reverse jet scrubber[a] downstream of the mud incinerator to increase SO_2 and particulate removal (B).

amount of particulate, with sizes assumed to be between 0.5 µm–1 µm. The customer requested the flue gas treatment to be designed to remove at least 50% of that particulate matter, which the scrubber was able to guarantee (**TABLE 2**).

Increased scrubber efficiencies. A further benefit of the proprietary reverse jet scrubber is that, for higher removal efficiencies, one can simply add multiple stages of reverse jet nozzles in series, thus creating multiple separate froth zones and significantly increasing removal efficiencies. Designing the scrubber with two reverse jet stages within the same inlet barrel effectively doubles the acid gas removal efficiencies.

Such a design will obviously increase the overall scrubber pressure drop, but, since dust removal efficiency depends on the particle size distribution of the particulates coming in and also on the pressure drop across the system, adding another stage of reverse jet nozzles in the same inlet barrel will, at the same time, achieve a significantly improved removal efficiency for the particulate at a very limited incre-

mental capital expenditure. It is worth noting that, with this technology, the pressure drop does not fluctuate or creep up, but remains constant. This is a very inexpensive way to increase scrubber efficiency.

What if the feed stream changes? If refineries suddenly have a new contaminant in their mud incineration offgas, or if there is a spike in the acid content of the inlet gas, this system is extremely flexible
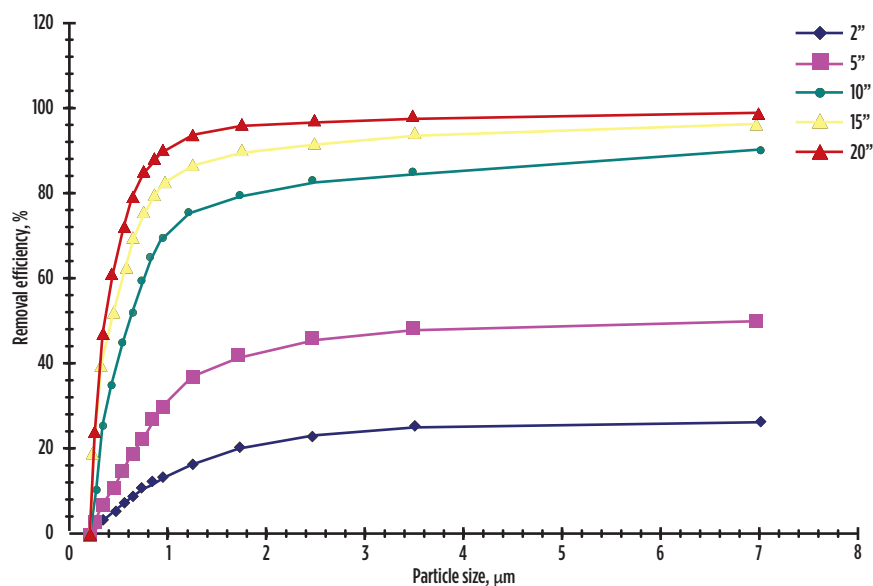

FIG. 4. Removal efficiency of the proprietary reverse jet scrubber in relation to particulate size distribution and pressure drop.

and will adjust based on the pH. If there is more acid gas, it will be absorbed into the scrubbing liquid. The pH of the scrubbing liquid will drop. The system will add more of the reagent being used in that particular system to raise the pH to maintain the efficiency of the scrubber. The scrubber is usually operated at a pH of 6–7, although it can be operated at a higher pH if the acid content of the inlet gas is higher than expected. Since the system oxidizes the sump of the scrubber, the system can function at a higher pH without causing scaling.

If there is a baghouse upstream of the scrubber that should fail or break, the proprietary reverse jet scrubber can handle
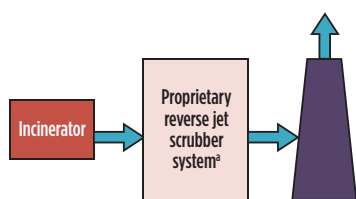

FIG. 5. Simplified scrubbing flow scheme downstream of the mud incinerator, with the proprietary reverse jet scrubber system[a] replacing both the lime scrubber and bag filter.

the additional particulate that would then consequently enter the scrubber system. The system can also handle considerable fluctuations in the inlet gas feed rate. Gas rates up to 120% above the design rate can be accommodated by adjusting the caustic rate and gas side pressure drop. As a rule of thumb, should gas rates drop, the turn-down rate for the proprietary reverse jet scrubber is approximately 60%.

Takeaway. The correct treatment and disposal of refinery waste products is a complex but critical process for an industry beset not only with having to meet strict environmental regulations but also stakeholder expectations. As a result, organizations that opt for incineration as a disposal method utilize multiple and often elaborate gas cleaning processes to meet legislator requirements and improve the sustainability of their operations. While there are several options for treating mud-incineration offgases, a custom-designed versatile scrubber can simplify the process.

Due to its ability to handle very hot inlet gas temperatures, and thanks to its patent-ed weir bowl technology, this proprietary reverse jet scrubber is an option that is capable of replacing all upstream gas treating equipment (such as the lime scrubber and bag filter) and still deliver low SO_2 and particulate levels at the stack outlet (**FIG. 5**). **HP**

NOTE
[a] MECS® DynaWave® reverse jet scrubber

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Safe work permit auditing: Is your system providing the expected results?

When the challenging position of manager is assumed in a refinery, one of the first orders of business is to "survive" an upcoming process safety management (PSM) compliance audit. The prior audit report has been read and several issues with work permitting have been noted. The team is called together and the following question is posed: Can the leading and lagging metrics for safe work permitting be shown? A moment of silence, and then the answer, "Metrics?"

This scenario is perhaps more realistic than supposed. While safe work practices (SWPs) have been a part of PSM regulations for decades, incidents related to the execution of these elements still occur. For example, lockout tagout (LOTO) violations have been among the top five U.S. Occupational Safety and Health Administration (OSHA) citations for several years. Other safe work items, such as fall protection and scaffolding, have similarly remained among the most frequent citations.

Having participated in hundreds of safe work audits, one of the most common opportunities the author has seen is the absence of a mature permit auditing process to gauge the effectiveness of a program. Most refineries and chemical plants exceed the minimum regulatory expectations for auditing LOTO, hot work and confined space entry. However, many of those audit programs lack the rigor that can be found in industry better practices.

Throughout the author's experience performing audits at refineries, chemical plants, terminals and midstream facilities, most shortcomings in audit programs fall into one or more of the following five categories:

- **Overreliance on "paper audits" of completed permits.** These types of "after the fact" reviews of *completed* work permits can provide insight into a facility's compliance with the program's administrative controls (signatures, etc.). However, they are ineffective in validating whether risks are being effectively managed while jobs are in progress. Field audits at job sites are necessary to determine if work is being executed safely (**FIG. 1**). A field audit would cover critical items such as:
  - Did a fire extinguisher (required in a hot work permit) meet National Fire Protection Association (NFPA) inspection requirements?
  - Were process sewers within 35 ft of hot work sealed or covered?
  - Were isolations in an LOTO at the closest point relative to the work being conducted?
- **Many audit checklists lack the granularity needed to identify specific gaps in safe work execution.** Comprehensive checklists not only ensure consistent application of the tool, but may also be an effective means to educate the auditor and worker (operations or maintenance) on the requirements.
- **The sample size of audits being performed may be too small.** The number of audits completed should be statistically representative of the overall work being performed. The majority of audits should focus on high-risk work, such as LOTO, hot work and confined space entries.
- **Findings from the audits are not being trended over time to identify common gaps in execution.** Most facilities are good at addressing a specific deficiency seen in the field at a specific job. However, they are not always leveraging the benefit of stewarding longer-term "themes" noted from the audits to help identify systemic issues.
- **Many facilities have not established metrics related to SW permitting.** To help gauge the health of programs, one of the most powerful leading indicators of safe

FIG. 1. At refineries, chemical plants, terminals and midstream facilities, field audits are necessary to determine if work is being executed safely.

work performance is the type and overall number of deficiencies captured during the field auditing process. Many sites steward key indicators, such as:

- The percentage of flawless audits from their field auditing program
- The number of high-consequence infractions noted during the audits.

High-consequence infractions are those deviations that could result in a significant incident or injury. Examples may include:

- No gas test performed prior to hot work
- No monitoring of the atmosphere inside a confined space
- Work being performed without proper isolation from an energy source .

Common deficiencies in audit programs have been highlighted here. In the following section, a roadmap (based on the author's experience) on the key elements of a mature SWP audit program will be provided.

SWP audit model. A detailed audit tool (checklist), as seen in **FIG. 2,** should be used to drive consistency. An audit checklist should have the level of granularity/detail to define specific requirements of the work. It should capture key regulatory standards (isolation point labeling for LOTO, removal of combustibles within 35 ft of hot work, etc.) as well as any site-specific requirements for those elements. The detailed findings from the audits will be valuable to guide a site on what corrective actions should be considered.

Consider utilizing front-line supervisors (operations and maintenance) along with safety personnel to perform audits. Using leading shift personnel to perform periodic field audits

not only engages them in the process, but educates them on the specific requirements and provides a forum to give coaching and counselling to their direct reports, as appropriate.

Many companies have incorporated audit checklists into cell phone or tablet apps to allow ease of use for performing audits. Most of the systems in the industry (auditing apps) also allow the trending of findings from those audits, eliminating manual manipulation of data.

As a best practice, consider utilizing contractor leading personnel and managers to perform audits of safe work activities using standardized checklists for consistency. All the data from these various tiers of audits can be used to identify trends in performance.

Ensure the sample size (number of audits) is adequate to be statistically representative. Designing a safe work audit program to audit at least 5% of all high-risk activities is recommended to ensure corrective actions and improvement initiatives are data-driven vs. a reaction to anomalies noted during the audits. Most field audits should be focused on safety critical activities. LOTO, hot work and confined space entries should represent at least 80% of auditing resources.

Periodically review themes noted during the audits, and use the data to identify improvements to close gaps. Many sites review the results from their auditing at least twice a year. The findings would suggest a) what seems to be working well, and b) what areas require development of improvement plans via refresher training, additional tool implementation, etc. In a mature system, line managers have a clear understanding (based on the findings from their program) of what areas need improvement.

Establish metrics from safe work auditing as a leading indicator of performance. Recommend stewarding at a minimum of a) the percentage of safe work audits that were flawless, and b) the number of high-consequence deviations noted during the audits.

- A line manager must always question any metric that shows the flawless rate to be perfect. If no deviations are noted, the auditors may not be looking hard enough, or the audit tool (checklist) may not have the level of detail needed to dive into the requirements.
- Periodically review these metrics at the site leadership team level as well as with affected employees and contractors involved in the safe work permitting process.

Takeaway. The development and implementation of a sound safe work audit program requires some level of resourcing to build sound audit tools, educate auditors using the tool, and periodically steward findings and leverage those learnings to enhance performance. Once an audit process is established, the program can provide valuable data on how facility leaders can drive improvements within their companies. **HP**

FIG. 2. A detailed audit checklist should have the level of granularity/ detail to define specific requirements of the work, and capture key regulatory standards as well as any site-specific requirements for those elements.

BOB BLUNDELL has more than 40 yr of experience in refinery operations, and served as a mid-level Manager with ExxonMobil before retiring in 2013. He is a Certified Assessor in the API Process Safety Site Assessment Program and has extensive experience in conducting refinery and terminal safety assessments. His expertise also includes safe work program development, alarm management and PSM compliance auditing. He now serves as a Process Safety Consultant for Ethos Process Safety Solutions.

Digitally uncover profitable pathways to net-zero

Many view COP26—the 2021 United Nations Climate Change Conference in Glasgow, Scotland—as a missed opportunity. However, it did score a few achievements, one of which is draft guidance on Article 6 of the Paris Agreement that is expected to pave the way for operationalizing effective carbon markets.

Energy executives should take notice, as this signifies the role economics and market mechanisms will play as industry decarbonizes. As many leading energy companies commit to net-zero targets, it is important to reaffirm that good planning, execution and the capability to demonstrate additionality in abatement measures can lead to an economically viable transition to net-zero. This article builds on the following themes:

- The need for energy companies to prioritize their emissions-related initiatives based on detailed analysis of technology options, market conditions and regulations
- The digital capabilities and solutions needed by organizations to uncover this profitable path to net-zero
- A recommended framework and next steps for organizations that wish to build this capability.

Net-zero or net profit? A survey of plans across energy companies and a review of abatement measures reveal the following broad phases or categories of initiatives companies are adopting.

Beginning with unlocking efficiencies, the focus is on increasing efficiencies either through better planning, optimization, control, operations or maintenance. This step is expected to be net-positive for the operators, with the measures often paying for themselves.

The next category is the progressive introduction of low-emissions compo-

nents into the value chain. These could be new low-emissions feedstocks, intermediates and blend components, equipment replacements, upgrades and additions that reduce emissions without changing the basic process configuration.

The final category of initiatives might require significant capital expenditure (CAPEX) and operating model changes, where today's operators become a hub for the distribution of low- or zero-emissions energy products. In the process, they also capture and sequester carbon produced for themselves and the surrounding industrial cluster.

While these phases serve to reiterate organizations' strategic intent, it is also evident that this is a simplistic and sometimes misleading view of how organizations will practically achieve their net-zero targets. Take energy efficiency as an example: its contribution towards decarbonization is often underestimated by executives and relegated to a few initiatives in the first phase. A 2019 report by the International Energy Agency (IEA)[1] estimates the cumulative impact from a range of digital technologies and advanced software applications could mean energy savings of up to 30% across the industry globally. These are significant savings in terms of greenhouse gas (GHG) emissions abated. Therefore, energy efficiency must be the focus throughout the net-zero journey as new feeds, equipment or units are introduced into the value chain, and new digital technologies become available.

In general, such simplistic net-zero plans fail to address the challenges from a complex interplay of technology, regulatory and market environments, and how these will evolve in the future. At present, the technology space for net-zero is extremely dynamic, with multiple

options being researched. This is a function of the investments being made as well as the demand.

A 2020 IEA report, "Energy technology perspectives,"[2] states that more than 33% of the cumulative emissions reductions in the Sustainable Development Scenario (SDS) stem from technologies that are not commercially available today. At the same time, policy and regulatory frameworks continue to evolve. The draft guidance on Article 6 of the Paris Agreement, mentioned earlier, talks of a centralized accounting and reporting platform. This will drive a more rigorous GHG reporting regime globally and encourage more comprehensive carbon pricing initiatives. Such developments will affect the market environment, incentivizing specific initiatives differently depending on how these scenarios play out. This also provides an opportunity for companies that can navigate this better than competitors and leverage market mechanism.

OPTIMIZE THE CARBON CHAIN WITH THE VALUE CHAIN

As energy companies embark on select initiatives and projects on their journey to net-zero, they must develop solutions and capabilities that will guide them in a profitable fashion. Increasingly, GHG mitigations will be incentivized, or emissions penalized through market and non-market mechanisms. These solutions and capabilities will help organizations prioritize their initiatives based on existing and emerging technologies and, more importantly, evaluate them as various regulatory and market scenarios unfold. Energy companies must develop these forward-looking capabilities proactively rather than reactively, always considering the time needed to scale effectively. The winners

of the energy transition will be companies that can navigate this journey profitably.

The capability to successfully create, update and execute on a tenable net-zero roadmap should, as a minimum, comprise three key components (**FIG. 1**) that are discussed separately in greater detail below:

- **Carbon-aware planning:** The capability to create investment and operating plans considering Scope 1, 2 and 3 emissions.
- **Process digital twin-based energy and emissions management:** The capability to calculate emissions reduction potential to drive tactical, operational improvements.
- **Unified production and emissions accounting:** The capability to baseline and then track production, fuel and loss, ensuring more consistent reporting between emissions and production and linking emissions reduction to the bottom line through reduced fuel and loss (or increased production).

Companies with these capabilities will have a competitive advantage when balancing between profitability drivers and the new GHG- and sustainability-related drivers to find a profitable path to net-zero. These capabilities are not entirely new, but should be considered as enhancements of existing capabilities and solutions to address the upcoming challenges and create a sustainable competitive advantage as the industry transitions to net-zero.

Carbon-aware planning. This is an enhancement of existing planning models and solutions to address future carbon pricing and carbon caps or limits. It provides organizations the capability to make investment plans based on various carbon pricing and carbon cap scenarios.

The capability consists of having a planning solution that models direct emissions for the organization with appropriate rigor, including capturing the carbon intensity from feed to the final product and ensuring that all economically significant operations or activities and their associated emissions are modeled to be dependent on the level of operations or activity. This covers what are typically classified as Scope 1 emissions. Additionally, the capability should exist to model indirect emissions (Scope 2 and 3), typically based on supplier/customer published numbers, national or regional averages, or industry numbers. This would allow firms to assess the risk of rising carbon pricing and the impact of carbon caps from an overall (Scope 1, 2 and 3) carbon footprint basis. This is key when evaluating alternate feedstocks, energy sources and, in general, any make vs. buy decisions.

The modeling approach must be supported by collaboration with specialized teams from the process, sustainability and commercial/marketing segments. The uncertainty in technology, regulatory and market environments means that various scenarios of demand, prices and new technologies/processes must be evaluated. This information will be collected from specialists, and then different demand/pricing scenarios must be applied against a backdrop of varying policy environments and technology options.

Process digital twin-based energy and emissions management[3]. Carbon-aware planning provides the major investment guidance and planning insight into switching to low-emissions or green feed, energy options and producing low-carbon products. However, companies must also identify tactical opportunities for emissions reduction that might not significantly alter the process or require a significant CAPEX investment.

These improvement opportunities include performing maintenance work like exchanger cleaning, changing pump impellers, switching to low-carbon fuels in specific equipment, equipment level heat recovery, conservation and other abatement initiatives. Improvement opportunities will typically lower emissions or increase efficiency in the medium- to short-term, but are too granular or short-term to be adequately addressed by carbon-aware planning.

Companies have been using site-based norms or global/industry benchmarks to compare their energy and emissions performance and identify opportunities for improvement. The problem with using these norms is that they are too aggregated and averaged to provide addressable insights that can help prioritize actions. For example, industry benchmarks are effective at the unit or site level, but have limitations when it comes to prioritizing the potential for efficiency improvement or emissions reduction in the context of specific equipment (pump, motor, exchanger, etc.), considering the nature of site-specific operations.

Suppose that site-based norms for particular equipment or class of equipment based on history are used. In that case, they can provide a comparison based on historical averaged data but not the potential benefit, which can help managers prioritize actions. This is a challenge because feed sometimes can be heavy or light; it can contain high or low sulfur amounts. Similarly, the process may run alternately in a severe mode and a less severe mode. This operational context will impact the energy needed and the GHG emissions from the process.

Averaging the data removes this context—for that reason, the difference from an averaged static norm does not capture the true potential for reduction. Instead, if a digital twin for the process is used and run in parallel in a "green mode," it will calculate the most practically efficient norms for energy and emissions. The difference between the current value and dynamic target calculated by the "green"

Carbon aware planning
Economic investments and operating plans considering scope 1, 2 and 3 emissions

Process digital twin based energy and emissions management
Calculate energy and emission reduction potential

Unified production and emissions accounting
Align production and emissions accounting to baseline and track results into your sustainability reporting

Current emissions

Kg CO₂/MT crude

−10%
−30%
−50%
−80%
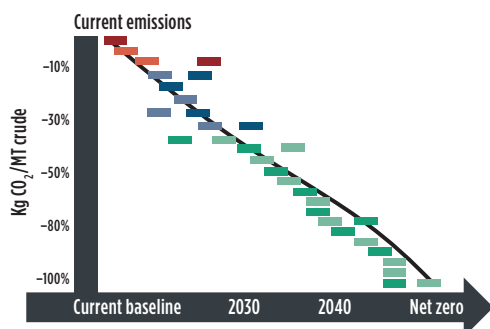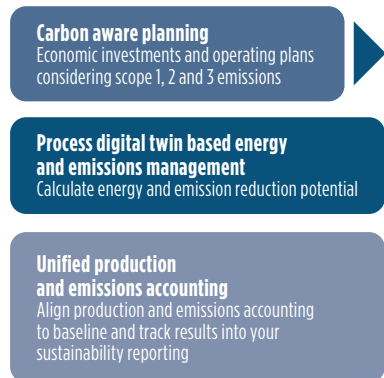−100%

Current baseline | 2030 | 2040 | Net zero

FIG. 1. Capabilities to successfully navigate to net-zero. Source: AVEVA.

digital twin can then provide an accurate view of the reduction potential for energy consumption and emissions (**FIG. 2**).

The first step is to collect plant data (**FIG. 3**), followed by data validation, gross error detection and reconciliation, a critical step to ensure fidelity and accuracy of outcomes. The digital twin can then be run in green mode to calculate the dynamic target[4] based on the most practical and efficient operation, considering feed rate, quality, composition and independent parameters, such as ambient conditions, while meeting product rate and specification requirements.

This approach makes it possible to calculate the reduction potential for various improvement opportunities—equipment cleaning and maintenance, replacement and upgrades, and heat conservation projects—that impact energy consumption and emissions. This reduction potential then helps prioritize these initiatives based on accurate estimates of benefits. As stated earlier, the capability to find the most beneficial and profitable initiatives in the correct order will be critical to navigating to net-zero successfully. Additionally, the digital twin can also optimize the process based on economic drivers, providing further benefits.

Unified production and emissions accounting. GHG accounting and reporting principles continue to evolve. It is expected that as carbon markets become operational and the cost of emissions is felt more tangibly, the focus on completeness, consistency, transparency and accuracy of emissions reporting will increase.[5]

Organizations must bring more assurance to Scope 1 emissions reporting. In this context, it is essential to distinguish between reporting requirements (from a regulatory perspective) and the level of accounting that a company desires to achieve. A critical capability for companies will be to develop an accounting system capable of handling future reporting requirements that is granular enough to track reductions in emissions through various initiatives. Additionally, it should also reconcile GHG emissions accounting with overall production accounting. This overall hydrocarbon + GHG accounting approach not only improves the consistency and accuracy of numbers, but also connects emissions to overall fuel and loss in a business-centric focus.[6]

Fuel and loss has been a traditional metric in the energy industry—in turn, reduction in fuel and loss drives efficiency and production (**FIG. 4**). It is not uncommon to achieve significant reductions in loss through a well-managed loss management program; this traditionally requires good estimation on various emissions, effluents and fuel usage. A rigorous, unified production and emissions accounting system provides the opportunity to achieve those reductions in loss numbers and sustain them. It also promotes credibility in the reported numbers and reduces the uncertainty in emissions data, bringing it in line with production numbers.

Scope 2 and 3 are indirect emissions, and are the consequence of the activities of the reporting company; however, they occur at sources owned or controlled by another company or entity. A reporting company is generally unable to measure these emissions directly at the source, but rather relies on a variety of sources like supplier or customer published numbers, national or regional averages or industry numbers (on a per-unit basis), and the level of underlying source activity based on in-house data (where available). The underlying source activity for Scopes 2 and 3 emissions are often captured in transaction systems [e.g., sale, purchased in enterprise resource planning (ERP)] for the reporting company. Companies can confirm they are capturing this data in sufficient detail. Since Scope 2 and 3 emissions for one company are Scope 1 emissions for other companies in the supply chain, a sectoral improvement in emissions reporting will
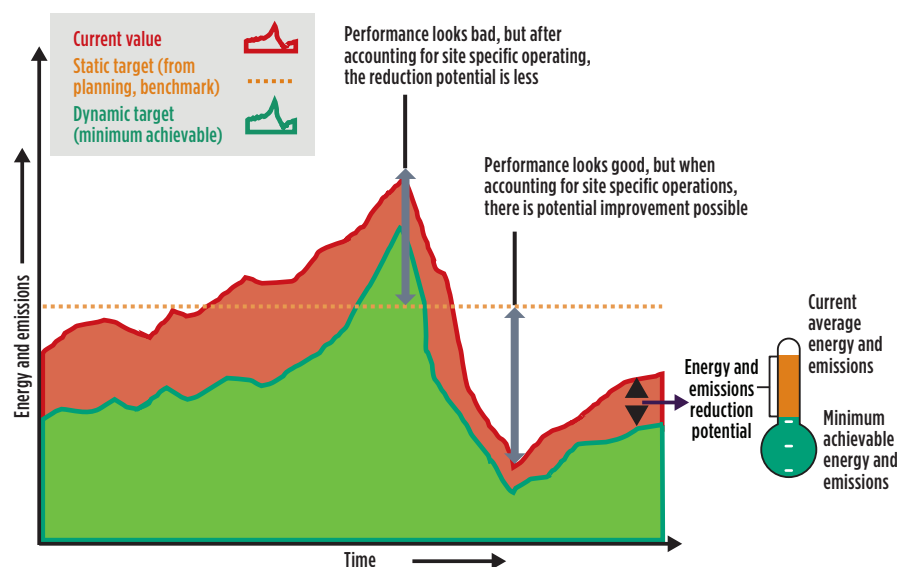

FIG. 2. Energy and emissions reduction potential can provide addressable insights. Source: AVEVA.
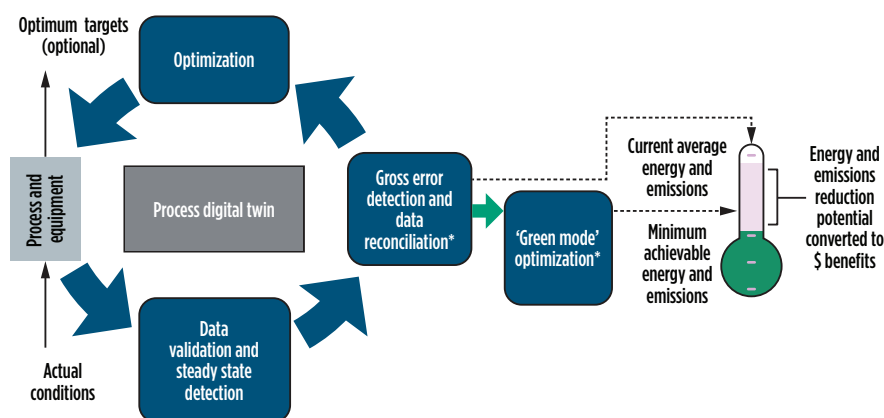

FIG. 3. Calculating energy and emissions reduction potential using a process digital twin. Source: AVEVA.
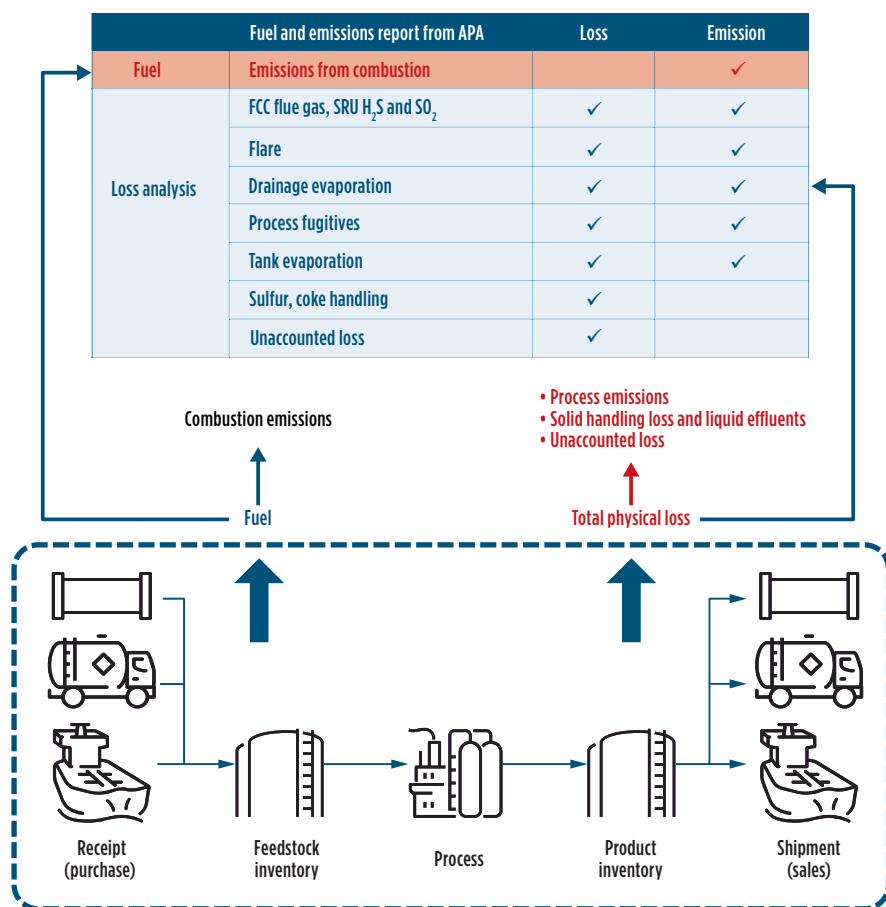
Fuel and emissions report from APA		Loss	Emission
Fuel	Emissions from combustion		✓
Loss analysis	FCC flue gas, SRU H$_2$S and SO$_2$	✓	✓
	Flare	✓	✓
	Drainage evaporation	✓	✓
	Process fugitives	✓	✓
	Tank evaporation	✓	✓
	Sulfur, coke handling	✓	
	Unaccounted loss	✓	

Combustion emissions

• Process emissions
• Solid handling loss and liquid effluents
• Unaccounted loss

Fuel

Total physical loss

Receipt (purchase) — Feedstock inventory — Process — Product inventory — Shipment (sales)

FIG. 4. Unifying GHG emissions and sustainability metrics with fuel and loss. Source: AVEVA.

FIG. 5. Management system to attain net-zero objectives. Source: AVEVA.

objective targets for emissions reduction and prioritize actions and initiatives based on economics. The ability to monitor and track their progress will help them uncover a profitable path to net-zero. Markets and shareholders will reward companies that demonstrate this capability earlier than others. Companies interested in capturing this opportunity should review their management systems around energy and emissions reporting and management and enhance them by using systems and solutions for carbon-aware planning, process digital twin for energy and emissions management, and unified production and emissions accounting. **HP**

lead to a more accurate basis for indirect emissions reporting.

Bringing it all together. Alone, these capabilities are insufficient: they must work together towards the net-zero target utilizing a plan-do-check-act (PDCA) framework, as shown in **FIG. 5,** driving iterative and continuous improvement. Driving net-zero targets requires cross-functional collaboration across the value chain, so it is essential to embed the systems and capabilities into the entire supply chain operations. One way is to leverage existing systems, processes and standards already in place. Few such systems to consider are:

• International Organization for Standardization (ISO) 50001 for energy management provides a PDCA-based framework that can be extended to emissions management to guide the journey to net-zero.
• ISO 14000 family of standards, including ISO 14001

(Environmental Management Systems) and ISO 14064 (Greenhouse Gases).

The capabilities discussed here—the use of a digital twin to calculate a rigorous, engineering-based view of energy and emissions reduction potential; and unified production and emissions accounting with a more detailed analysis of fuel and loss—enable a more robust adoption of these systems and standards, overcoming traditional limitations seen in typical deployment (these functions have traditionally been carried out using an array of user-specific Excel calculations). A system and standard-based approach where carbon-aware planning and process digital twin-based energy and emissions management help set targets and prioritize actions. Unified emissions and production accounting enables tracking, monitoring and reporting of achievements against targets, and can provide organizations a competitive advantage on the journey to net-zero.
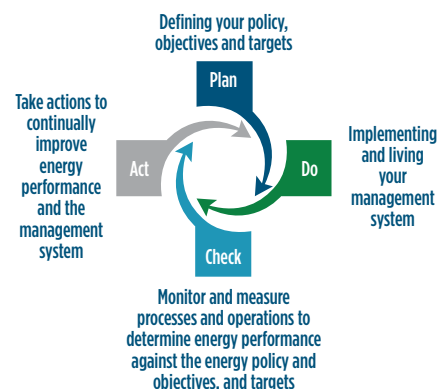
Energy companies must generate

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HP | Heat Transfer

A. K. DIXIT, Graham India Pvt. Ltd., India

Modularization of air-cooled heat exchangers: A "plug and play" solution

An air-cooled heat exchanger—also called an air fin cooler—is used to reject the heat from a fluid (liquid or gas, or a mixture of liquid and gas) directly to the ambient air. The hot fluid flows inside the finned tubes of the tube bundle, while the cold ambient air passes outside the finned tubes in a cross-flow to exchange the heat. The ambient air can be forced by using a fan coupled with a motor, or without fans (i.e., by natural convection). In general, the tube bundle assembly is mounted on its support structure of suitable height, ensuring sufficient stack for air entrance.

Air-cooled heat exchangers are used in a wide range of industries and products, typically including gas compressor packages, engine cooling, lube oil cooling, condensing of propane or refrigerants in liquefied natural gas (LNG), thermic fluid heating in LNG, steam condensers in cement and power plants, process cooling applications in refineries and petrochemicals, and many others.

The supply of air-cooled heat exchangers in a "pre-assembled module" is a new methodology to overcome the challenge of its long erection time and cost, and the lack of skilled and experienced personnel at a project site.

In an air-cooled heat exchanger, a pre-assembled module typically comprises tube bundles with guards, support structure with top segment columns, temporary transportation bracings and beams, header walkways, plenum and fan rings, a drive structure, fans and motors, and coupling and vibration instruments—the loose component may include the bottom segment of support columns, permanent bracings, stairs and handrails, and variable frequency drives (if applicable).

Depending upon the process requirement and site conditions, an air-cooled heat exchanger can be in a forced-draft or an induced-draft configuration. The extent and outline of the module formation depends upon the configuration of the air-cooled heat exchanger, in addition to other factors. Based on learnings from recently executed projects, the most-effective practice of module formation for an air-cooled heat exchanger that avoids numerous interferences and significantly benefits a project schedule is presented here.

Module formation of a forced-draft, air-cooled heat exchanger. In a module of forced-draft, air-cooled heat exchangers with direct or belt-driven fans and motors located at the bottom of the tube bundles, the supporting structural columns should be made in two segments with a splice connection located approximately 300 mm below the bottom of the motors. The top segment of the columns will be part of the module, while the lower segment is to be supplied as loose. **FIG. 1** shows this kind of configuration.

In air-cooled heat exchangers with fans and motors, both located at the top of the tube bundle, the supporting structural columns are not required to be in segments. In this case, tube bundles with plenum, fan ring, fans, motors and drive assembly should form a module.

Module formation of an induced-draft, air-cooled heat exchanger. The practice of constructing the supporting structural columns in segments and locating the splice connection is the same for an induced-draft, air-cooled heat exchanger, with the direct or belt-driven fans located at the top and motors located at the bottom of the tube bundles, as illustrated in **FIG. 2**.

Potential benefits in adopting a modular supply of air-cooled heat exchangers. The pre-assembled module can take less than 1 d to erect at a project site with little to no supervision, while the older knock-down supply can take 3 d–4 d with the appropriate supervision of skilled and experienced site personnel. This savings is exponential with the num-

1. Fan
2. Fan ring
3. Plenum
4. Nozzle
5. Header
6. Tube bundle
7. Drive assembly
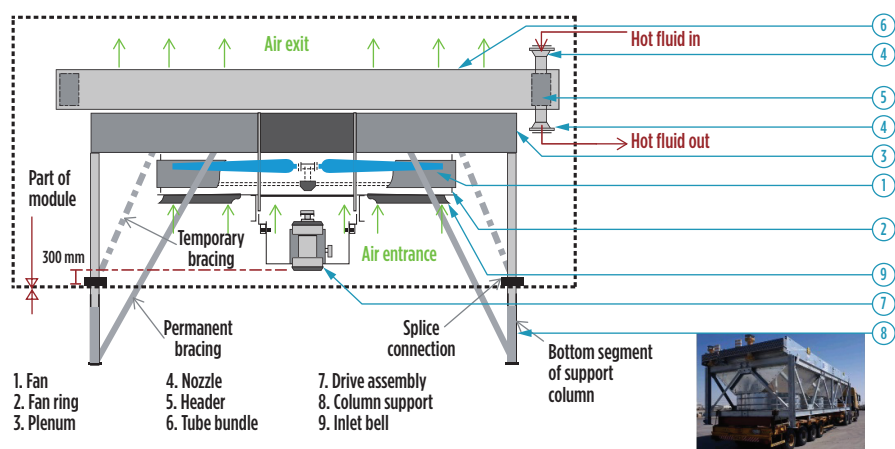8. Column support
9. Inlet bell

FIG. 1. A module of forced-draft, air-cooled heat exchangers with direct or belt-driven fans and motors located at the bottom of the tube bundles.

ber of bays or modules of air-cooled heat exchangers required in a project.

the supplier's factory works to the project site—is essential to ensure the safe trans-

tion of the support structure columns in modular supply, the air-cooled heat exchanger supplier must ensure that these junction boxes and local control stations do not interfere with splice connection fasteners. Otherwise, the engineering, procurement and construction (EPC) contractor should be informed in advance to find another suitable location for the junction box and local control station.

> The transportation of modular air-cooled heat exchangers from factory works to the project site—by sea, inland transportation or both—is critical and numerous factors impact costs.

The dismantling of air-cooled heat exchangers that have been assembled to conduct factory/shop run-in tests is not required in the case of modular supply—a single module or a bay saves approximately 250 work hours, as well as wear on machinery.

Transportation costs associated with the modular supply of small- to medium-size air-cooled heat exchangers (i.e., not an over-dimensional consignment) are less than its knock-down supply, as the number of trucks and trailers required to transport dismantled supporting structures, plenum and fan rings, tube bundles, etc., is reduced.

For projects where the site location has limited approachability for plant erection due to adverse climate conditions in one or more seasons, or when a fast-tracked project faces challenges in the availability of skilled and experienced site personnel, adopting a modular supply of air-cooled heat exchangers becomes essential to overcome these challenges.

A checklist and general direction for the modular supply of air-cooled heat exchangers. A route survey—from

portation of the modules. The transportation limitations in length, width and height of the module are determined based on this route survey. A thermal engineer must consider these transportation limitations while sizing the air-cooled heat exchangers.

In the case of modular supply of air-cooled heat exchangers, each individual bay (typically a module) has its independent supporting structure. Therefore, a gap of approximately 450 mm should be between two adjacent bays. The piping engineer preparing the plot plan must account for this: ideally, this gap should also be sealed with air sealing plates at the top of the steel elevation level to avoid any air recirculation.

The air-cooled heat exchanger supplier will perform an additional structural calculation of the module to determine the optimum sizes of temporary bracings and beams required for transportation purposes.

A local junction box for vibration instruments and a local control station for the motor are often installed on support structure columns of the air-cooled heat exchanger. Due to the splice connec-

The tube bundle is the heaviest part of an air-cooled heat exchanger to be lifted in case of knock-down supply. However, a module is much heavier and larger than its tube bundle alone. Therefore, the air-cooled heat exchanger supplier must carefully design and use a proper certified lifting arrangement for a module.

During the onsite erection of the module, permanent bracings should be assembled before dismantling the temporary transportation bracings. This must be specifically highlighted by the air-cooled heat exchanger supplier in its erection manual.

Takeaway. The modular supply concept of air-cooled heat exchangers in any project can save substantial factory and site activities, while minimizing the supervision of skilled and experienced site personnel. Many reputed EPC contractors, project managing companies and owners of leading refineries, petrochemical and LNG projects have already sourced air-cooled heat exchangers in modular condition to enable faster plant erection. LNG projects require numerous air-cooled heat exchangers in both of their terminals (i.e., liquefaction terminals and regasification terminals). Considering the potential benefits and ease in adoption, the modular supply of air-cooled heat exchangers in LNG projects has become an industry train. A structural engineer can further add value to this concept by optimizing the structural design to avoid the scraping of temporary transportation bracings and beams by utilizing them as permanent equipment. **HP**
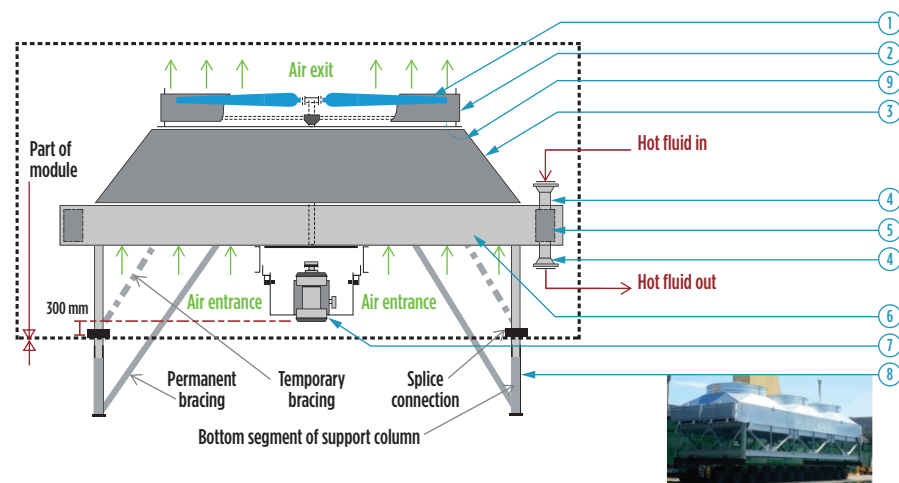
FIG. 2. An induced-draft, air-cooled heat exchanger with the direct or belt-driven fans located at the top and motors located at the bottom of the tube bundles.

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Optimize a cascaded cooling water network

Waste heat in process units is removed via heat exchange with a recirculating cooling water supply and return stream (**FIG. 1**). The heat picked up by the cooling water exiting the network of heat exchangers is removed via direct contact with ambient air in a direct contact cooling tower.

While numerous strategies and publications exist related to optimizing the cooling tower operation, this article focuses solely on the optimization of cooling water networks within a refinery process unit.

In the past, process engineers have given a lower priority to optimizing cooling water networks. Many process units either used more cooling water and energy than necessary or supplied a surfeit of cooling water to a few users at the expense of failing to deliver sufficient cooling water to many others.

The optimization of a cooling water network has now become a major design consideration for improving the operability and profitability for the end user. The objective of this analysis is to reduce the operational expenditure (OPEX) and, therefore, increase profitability. In many instances, this type of optimization has also resulted in reducing capital expenditure.

An analysis is presented here of a cooling water network for a refinery process unit initially considered for implementation, and the subsequent network optimized using commercially available hydraulic analysis software. While the case study analyses presented are for a specific process unit in a grassroots refinery installation, the concepts are fundamental in nature and may be broadly applied to any cooling water network.

Cooling water networks. In a typical network, all services are supplied with cooling water at the same temperature (**FIG. 2**).
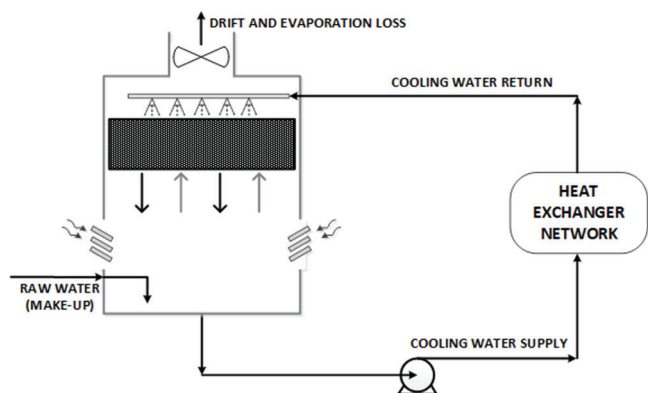
While the supply pressure at each user may vary depending on the elevation of the exchanger above grade level, the pressure in the cooling water return header is usually the same (or very similar) for all users.

Such an arrangement demands a substantial amount of water circulation. Moreover, due to the maldistribution caused by differences in elevations above grade and hydraulic resistances in piping and/or heat exchangers, a prudent process design will often include a sizable design margin (20%–25%) over and above the initial cooling water utility balance, as determined from process datasheets.

The above approach is a classic example of how cooling water networks were designed in the past. However judicious this may appear, it fails to take advantage of the fact that some services may accept a higher supply temperature with negligible or minimal thermal impact. In such a scenario, a secondary cooling water header (**FIG. 3**) is supplied with cooling water "cascaded" from some services supplied by the "primary" cooling water header—this can be considered a means of reducing the cooling water recirculation rate.

Though fundamentally simple in concept, the cascaded cooling water network requires a more elaborate hydraulic analysis due to the combination of a parallel and series-parallel network
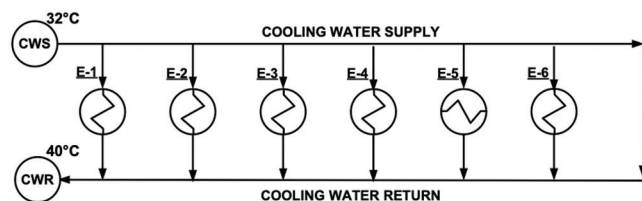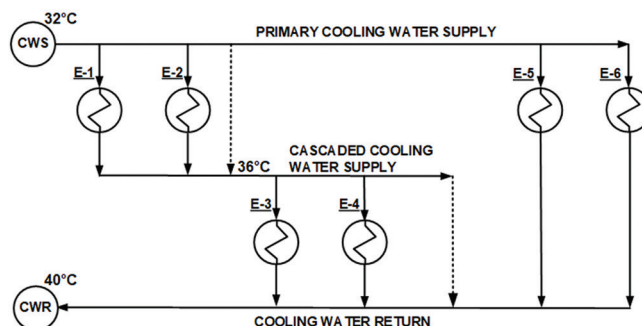

FIG. 2. Typical cooling water network.

FIG. 3. Cascaded cooling water network.

FIG. 1. Recirculating cooling water system.

of heat exchanger services. Such a complex hydraulic analysis can be performed using commercially available software[a] capable of modeling the entire network in which each node in the network is balanced based on flow conservation, and then corrected with a calculated pressure drop until the mass and energy balances are solved. The Newton-Raphson[1] technique is used to solve the matrices developed by a multi-nodal network system. Each node is iteratively solved for flow until the overall system pressure drop is actualized to satisfy the given constraints.

Heat exchanger pressure drops are modeled as resistance curves proportional to the square of the volumetric flow. Consequently, the hydraulic model of the network self-adjusts the flow of cooling water into each heat exchanger to maintain a realistic pressure profile across the entire network. Each heat exchanger is modeled with its elevation above grade and with either a fixed duty specification or a fixed temperature rise.

TABLE 1. Initial vs. Base Case cooling water balances

Item No.	Initial balance (data sheet), kg/hr	Base Case hydraulic balance, kg/hr	Duty, 10⁶kcal/hr	ΔT, °C
E-1	1,890,289	2,600,975	3.2	1.2
E-2	1,890,289	2,587,740	3.2	1.2
E-3	1,890,289	2,547,429	3.2	1.3
E-4	1,890,289	2,537,358	3.2	1.3
E-5	1,263,162	1,265,290	1.91	1.5
E-6	825,089	1,038,988	1.25	1.2
E-7	43,808	50,187	0.25	5
E-8	8,672	9,906	0.05	5
E-9	36,069	56,282	0.23	3.8
E-10	169,841	247,123	1.12	4.5
E-11	51,104	65,121	0.61	9.4
E-12	285,585	348,685	4	11.4
E-13	69,413	90,974	0.4	4.4
E-14	311	5,006	0.004	0.9
E-15	6,592	10,754	0.09	8.3
E-16	19,088	44,174	0.08	1.8
E-17	5,041	14,558	0.06	4.3
E-18	4,862	28,740	0.06	2.1
E-19	372,010	548,217	1.69	3.1
E-20	556,487	700,814	2.54	3.6
E-21	1,552,247	3,080,104	28.8	9.3
E-22	2,336,021	3,356,801	9.61	2.9
E-23	2,336,021	3,356,801	9.61	2.9
E-24	494,842	874,907	6.03	6.9
E-25	494,842	874,907	6.03	6.9
E-26	12,131	49,055	0.16	3.1
E-27	12,580	152,637	0.09	0.6
E-28	596,164	696,213	2.47	3.6
E-29	6,851	45,175	0.08	1.9
Total	**19,119,989**	**27,284,921**	**90**	**3.3**

PROCESS DESIGN CONSIDERATIONS

The process design of a cooling water network involves balancing the combination of the following process design considerations to reduce the cooling water circulation:

- Line sizing
- Cooling water supply pressure
- Hydraulic analysis
- Auxiliary supply networks
- Cascaded network.

Line sizing and cooling water supply pressure are the only variables that can be manipulated to control the flow and velocity of cooling water to each exchanger. The other three design considerations require a more in-depth discussion and are more readily understood by an analysis of a real-world case study.

Line sizing. The main criterion for sizing cooling water lines is maintaining a velocity high enough to avoid sedimentation and low enough to prevent erosion. Typical limits are between 1.5 m/sec and 4.5 m/sec, with the high end also being limited by pipeline pressure drop.

Cooling water supply pressure. The pressure required in the cooling water supply (CWS) header is set either by the greater of the sum of frictional resistances in the piping and heat ex-
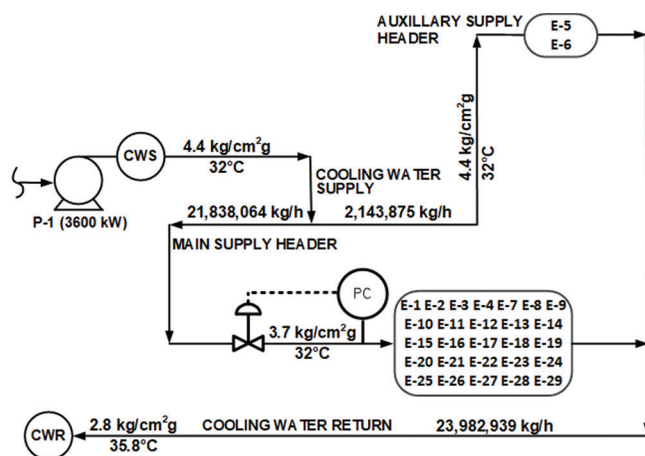

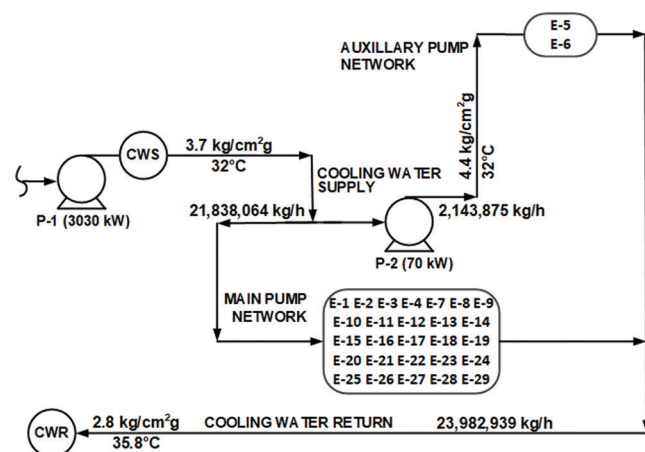**FIG. 4.** Base Case: Pressure control network.

FIG. 5. Base Case: Auxiliary pump network.

changers or by the pressure required to deliver cooling water to the heat exchanger located at the highest elevation above grade. Setting the supply pressure to satisfy the second criterion results in a higher differential pressure to all other services, resulting in an increased flow of cooling water.

Hydraulic analysis. As an initial starting point, all cooling water services should be specified for the same—or nearly the same—pressure drops to a practical extent. Subsequently, the cooling water rate should be adjusted by performing a hydraulic analysis of the entire network. Such an analysis should be plot sensitive and account for the take-off sequences and actual equipment elevations referenced from grade level. A comparison of the cooling water "initial balance"—determined from process datasheets with the "Base Case hydraulic balance" derived from the hydraulic analysis of the network—is summarized in TABLE 1.

The actual flow of cooling water differs from the datasheet values to satisfy the available differential pressure between the CWS and cooling water return (CWR) headers. Notably, heat exchangers E-5 and E-6 are located 40 m above grade and require an increase in supply pressure from 3.7 kg/cm²g to 4.4 kg/cm²g. Since the 2.8 kg/cm²g back pressure in the CWR header is the same for all services, the increase in the available differential pressure resulted in additional flow of cooling water to the other services.

Auxiliary supply network. In cases where only a few services govern the required supply pressure, it may be beneficial to con-

FIG. 6. Preliminary cascaded cooling water network.

FIG. 7. Workflow schematic.

sider implementing auxiliary supply headers at two (or more) pressure levels. The pressure in each header can then be tailored for the services supplied by that header. Implementing supply headers at multiple pressure levels can be accomplished by either throttling the pressure to an auxiliary header, or by boosting the pressure by using auxiliary pumps. Jin Sun[2], *et al.* have proposed an algorithm for determining an optimal number of auxiliary pumps and their installation locations.

Either of these two concepts can be applied to reduce the Base Case cooling water balance (TABLE 1). Segregation of the heat exchangers located at higher elevations above grade (E-5 and E-6) allows cooling water to be supplied at two different pressures, 4.4 kg/cm²g for E-5 and E-6 and 3.7 kg/cm²g for all others. The Base Case balance modified with an auxiliary network at the higher pressure is summarized in TABLE 2.

Supplying cooling water via an auxiliary header to heat ex-

TABLE 2. Initial vs. modified Base Case cooling water balances

| Item No.	Initial balance (data sheet), kg/hr	Base Case balance modified network, kg/hr	Duty, 10⁶kcal/hr	ΔT, °C
E-1	1,890,289	2,245,776	3.2	1.4
E-2	1,890,289	2,235,694	3.2	1.4
E-3	1,890,289	2,204,780	3.2	1.5
E-4	1,890,289	2,197,184	3.2	1.5
E-5	1,263,162	1,296,808	1.91	1.5
E-6	825,089	847,067	1.25	1.5
E-7	43,808	43,950	0.25	5.7
E-8	8,672	8,672	0.05	5.8
E-9	36,069	49,237	0.23	4.4
E-10	169,841	216,025	1.12	5.2
E-11	51,104	57,026	0.61	10.8
E-12	285,585	304,756	4	13.1
E-13	69,413	79,626	0.4	5
E-14	311	4,369	0.004	1
E-15	6,592	95,391	0.09	0.9
E-16	19,088	38,334	0.08	2.1
E-17	5,041	12,645	0.06	4.9
E-18	4,862	24,947	0.06	2.4
E-19	372,010	476,684	1.69	3.6
E-20	556,487	613,308	2.54	4.1
E-21	1,552,247	2,685,105	28.8	10.7
E-22	2,336,021	2,922,791	9.61	3.3
E-23	2,336,021	2,922,791	9.61	3.3
E-24	494,842	762,315	6.03	7.9
E-25	494,842	762,315	6.03	7.9
E-26	12,131	42,937	0.16	3.5
E-27	12,580	133,528	0.09	0.7
E-28	596,164	609,393	2.47	4.1
E-29	6,851	39,534	0.08	2.1
Total	**19,119,989**	**23,982,989**	**90**	**3.8**
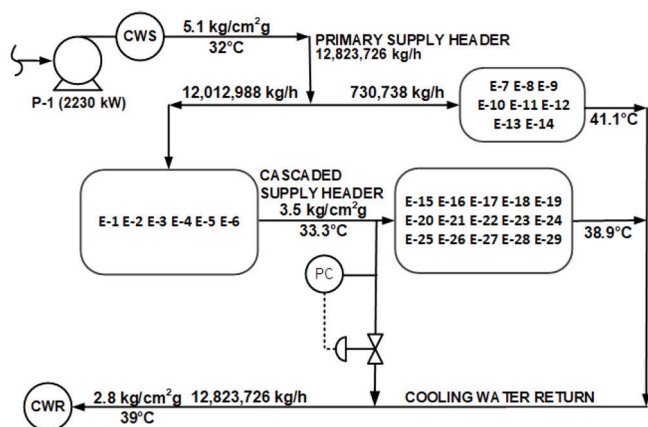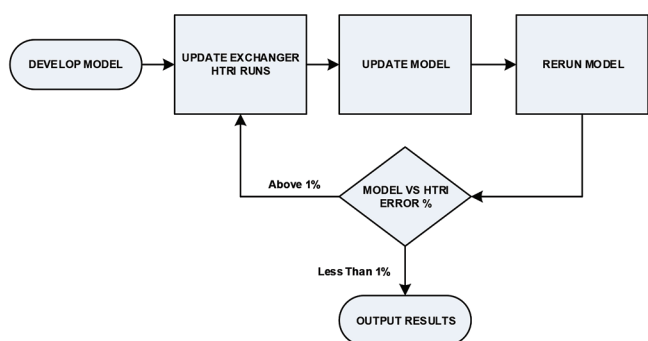
changers E-5 and E-6 that are located at a higher elevation than the rest lowers the cooling water demand for the Base Case hydraulic balance by ~12%, from 27,284,921 kg/hr (**TABLE 1**) to 23,982,989 kg/hr (**TABLE 2**). After segregating exchangers E-5 and E-6, the next limiting constraints for determining the supply pressure are exchangers E-7 and E-8.

Two alternate schematic representations of the network summarized in **TABLE 2** are depicted in **FIGS. 4** and **5**. While both networks require the same amount of cooling water, a considerable difference exists in energy consumption and, consequently, OPEX. The auxiliary pump network (**FIG. 5**) saves approximately 500 kW (14%) over the pressure controlled network (**FIG. 4**). The initially higher CAPEX required for the auxiliary

pump network can usually be offset by the lower OPEX within a short period of time.

Cascaded network. A cascaded cooling water network (**FIG. 3**) comprises primary and cascaded headers. The primary header receives cooling water at the battery limit supply temperature, while the cascaded header is supplied by the primary cooling water that has already been used in selected heat exchangers. The choice between which services are supplied by the primary header and which are supplied by the cascaded header is usually clear cut. Primary users typically have a relatively low rise (< 4°C) in cooling water temperature and therefore a high cooling water demand.

TABLE 3. Cascaded cooling water balance

Item No.	Primary header, kh/hr**	Cascaded header, kg/hr**	Return header, kg/hr**
CWS from BL	12,823,726		
E-1	–2,413,657	2,413,657	
E-2	–2,410,918	2,410,918	
E-3	–2,407,427	2,407,427	
E-4	–2,407,988	2,407,988	
E-5	–1,383,548	1,383,548	
E-6	–989,450	989,450	
E-7	–55,684		55,684
E-8	–10,713		10,713
E-9	–61,622		61,622
E-10	–224,562		224,562
E-11	–55,304		55,304
E-12	–322,758		322,758
E-13	–75,588		75,588
E-14	–4,507		4,507
E-15		–98,655	98,655
E-16		–37,423	37,423
E-17		–12,378	12,378
E-18		–24,453	24,453
E-19		–467,518	467,518
E-20		–632,708	632,708
E-21		–2,642,339	2,642,339
E-22		–2,869,597	2,869,597
E-23		–2,869,597	2,869,597
E-24		–750,952	750,952
E-25		–750,952	750,952
E-26		–43,698	43,698
E-27		–138,722	138,722
E-28		–632,931	632,931
E-29		–41,065	41,065
Bypass flow		0	0
CWR to BL			–12,823,726

Negative values (–) represent outflow, while positive values represent inflow.

TABLE 4. Cascaded cooling water balance with auxiliary pump

Item No.	Primary header, kh/hr**	Cascaded header, kg/hr**	Return header, kg/hr**
CWS from BL	11,358,460		
E-1	–1,931,807	1,931,807	
E-2	–1,930,831	1,930,831	
E-3	–1,928,320	1,928,320	
E-4	–1,928,829	1,928,829	
E-5	–1,188,100	1,188,100	
E-6	–113,000		113,000
E-7	–51,900		51,900
E-8	–9,929		9,929
E-9	–52,667		52,667
E-10	–246,480		246,480
E-11	–55,494		55,494
E-12	–299,110		299,110
E-13	–69,161		69,161
E-14	–4,558		4,558
E-15		–10,832	10,832
E-16		–35,414	35,414
E-17		–11,761	11,761
E-18		–23,121	23,121
E-19	–1,063,385	1,063,385	
E-20	–484,889	484,889	
E-21		–2,369,575	2,369,575
E-22		–2,775,973	2,775,973
E-23		–2,775,973	2,775,973
E-24		–714,046	714,046
E-25		–714,046	714,046
E-26		–77,955	77,955
E-27		–167,585	167,585
E-28		–257,516	257,516
E-29		–36,681	36,681
Bypass flow	–485,683		485,683
CWR to BL			–11,358,460

Negative values (–) represent outflow, while positive values represent inflow.

Heat exchangers E-1 through E-4 (**TABLE 1**) are integral with a reactor cooling system where it is desirable to maintain isothermal conditions. Heat exchangers E-5 and E-6 require a higher supply pressure due to their high (40 m) elevation from grade. Heat exchangers E-1 through E-6 have a low (< 2°C) temperature rise; however, the combined cooling water flow for these services is nearly 50% of the total requirement, thus heat exchangers E-1 through E-6 are suitable candidates as primary users.

Additionally, it is essential that the selection of primary and cascaded services be coordinated with the thermal design of the heat exchangers. A cooling water balance based on the cascaded network is provided in **TABLE 3.** The accompanying process schematic (**FIG. 6**) provides the pressure, temperature and flowrates for each header in the network.

The cooling water demand in the primary header is generally greater than (or equal to) the demand in the cascaded header. A pressure-controlled bypass (**FIG. 6**), which diverts flow from the cascaded header directly to the return header, may be required to maintain the water balance for users on the cascaded water circuit. In rare cases where the demand for the cascaded cooling water circuit is higher, it may be necessary to implement a separate pressure-controlled auxiliary let down (not shown) from the primary header to the cascaded header to meet the full water demand for cascaded users.

Optimization. While the cascaded network can significantly reduce cooling water circulation, the system can still be further optimized. For example, the inclusion of a dedicated auxiliary network for heat exchangers at higher elevations (E-5

and E-6) would lower the supply pressure and reduce the excess cooling water flow to other services. Further improvement may be possible by rearranging some exchanger services between the primary and cascaded headers, revising thermal designs for improved logarithmic mean temperature differences (LMTDs), and redesigning heat exchanger geometries for more uniform pressure drops.

On further inspection of the cascaded cooling water balance (**TABLE 3**), it can be observed that no excess cooling water remains in the cascaded header. This may create operational issues due to minor fluctuations in cooling water flow and or temperature. As such, any reduction of cooling water to exchangers E-1 through E-6 will create a shortfall in the cascaded header.

FIG. 8. Cascaded network with auxiliary pump.
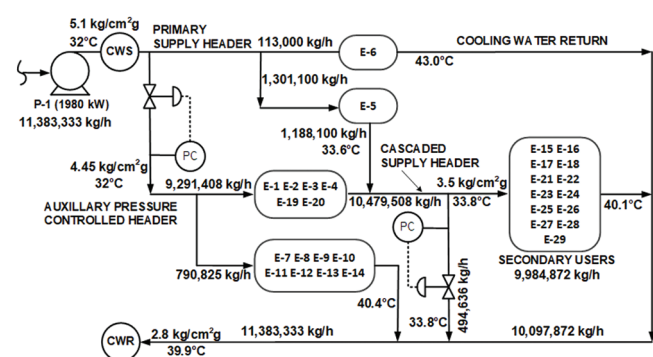
FIG. 9. Cascaded network with pressure control.

TABLE 5. Cascaded cooling water balance with pressure control		
Item No.	Primary header, kh/hr**	Cascaded header, kg/hr**	Return header, kg/hr**
CWS from BL	11,383,333		
E-1	–1,936,667	1,936,667	
E-2	–1,935,688	1,935,688	
E-3	–1,933,172	1,933,172	
E-4	1,933,683)	1,933,683	
E-5	–1,188,100	1,188,100	
E-6	–113,000		113,000
E-7	–52,001		52,001
E-8	–9,949		9,949
E-9	–52,769		52,769
E-10	–246,953		246,953
E-11	–55,600		55,600
E-12	–299,688		299,688
E-13	–69,298		69,298
E-14	–4,567		4,567
E-15		–10,846	10,846
E-16		–35,467	35,467
E-17		–11,778	11,778
E-18		–23,156	23,156
E-19	–1,066,051	1,066,051	
E-20	–486,147	486,147	
E-21		–2,373,013	2,373,013
E-22		–2,780,024	2,780,024
E-23		–2,780,024	2,780,024
E-24		–715,089	715,089
E-25		–715,089	715,089
E-26		–78,048	78,048
E-27		–167,789	167,789
E-28		–257,824	257,824
E-29		–36,725	36,725
Bypass flow		–494,636	494,634
CWR to BL			–11,383,333

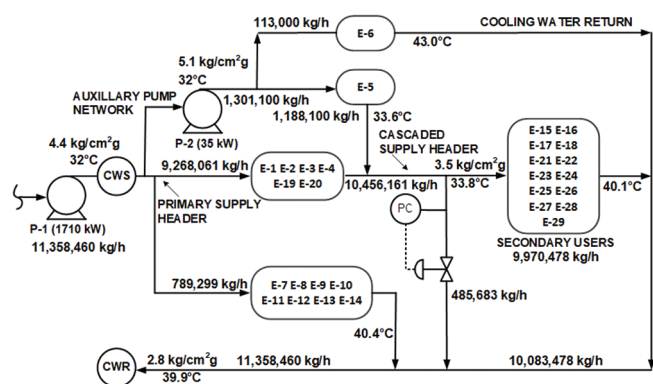Negative values (–) represent outflow, while positive values represent inflow.

TABLE 6. Summary of results

Case description	Cooling water required, kg/hr	Energy usage	
		kW	% of Base Case
Base Case hydraulic balance (**TABLE 2**)	27,284,921	4,100	100
Modified Base Case hydraulic balance with pressure control (**FIG. 4**)	23,982,939	3,600	87.8
Modified Base Case hydraulic balance with auxiliary pump (**FIG. 5**)	23,982,939	3,100	75.6
Cascaded cooling water network (**FIG. 6**)	12,823.73	2,230	54.4
Cascaded cooling water network with auxiliary pump (**FIG. 8**)	11,358,460	1,745	42.6
Cascaded cooling water network with pressure control (**FIG. 9**)	11,383,333	1,980	48.3

Therefore, it is recommended that a prudent design should cater for a nominal excess (~5%–10%) of the total flow in the cascaded header.

In the final analysis, only the thermal design and exchanger geometry for heat exchanger E-6 were changed for a lower cooling water rate. Also, at the lower cooling water rate, the high-temperature rise (11.6°C) required the cooling water from this exchanger to flow directly into the CWR header. To compensate for this change, heat exchangers E-19 and E-20 were reassigned as primary users, as these would benefit from a slightly higher LMTD. The final configuration of the network model was reconciled with the software used for the thermal design (HTRI). The workflow was an iterative process until the pressure drops and flowrates estimated in the network model were within 1% of the performance estimated using the thermal design software[a]. A schematic of the workflow is shown in **FIG. 7.**

An optimized version of the cascaded cooling water balance (**TABLE 4**) based on the use of an auxiliary pump for supply of cooling water to the two elevated heat exchangers E-5 and E-6, along with an accompanying process schematic are presented in **FIG. 8.**

For purposes of comparing the energy consumption, a similar balance based on using an auxiliary pressure controlled header (**TABLE 5**) and its accompanying process schematic (**FIG. 9**) are also presented.

Summary of results. The analyses presented here bring into sharp focus the need for considering cascaded cooling water networks as a means for lowering the cooling water circulation rate and reducing energy consumption. However, while this may have a marginally positive impact on the initial CAPEX, it is important to note that cascading the cooling water may not be suitable for all networks. In the case study presented here, the cooling water return temperature of 39.9°C was well within the specified constraint of 46°C. Some systems may result in return temperatures that could have an increase in fouling and corrosion, and the decreased LMTD could increase the required heat transfer surface area.

TABLE 6 shows a summary of results, clearly illustrating that a detailed hydraulic analysis of the cooling water network could result in significant water and energy savings if it is considered as part of basic engineering. Omitting this analysis may result in using more cooling water and energy than necessary or, in the worst cases, supplying excess cooling water to a few users at the expense of failing to deliver sufficient cooling water to many others. The hydraulic analysis should be integral with the process design of the unit and, as such, should not be relegated to

the detailed engineering phase when it may not be cost-effective to make configurational changes.

The advantages of utilizing an auxiliary network have been demonstrated. In the Base Case comparisons, the installation with the auxiliary pump uses 1000 kW less energy (a 24% reduction) with an estimated annual savings of $500,000 in OPEX. For the cascaded network comparisons, the installation with the auxiliary pump uses 485 kW less energy (a 22% reduction) with an estimated annual savings of $242,500. In either case, the CAPEX for the auxiliary pump can be recovered within a fairly short operating period (< 2 yr).

Comparison of the two auxiliary networks indicates that a pressure-controlled network requires more energy than a network without it: 500 kW for the Base Case networks (a 16% increase) and 235 kW for the cascaded networks (a 13% increase). For comparison purposes, the cost of energy usage for 8,400 hr of operation/yr is conservatively set at a nominal $500/kW ($0.06/kWh). Since energy costs vary from user to user, readers can substitute energy costs specific to their locations and cooling water balances to determine which of the auxiliary networks is more cost effective. **HP**

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Rotating equipment oil systems optimization guideline

The industry is moving away from oil shaft seals and hydraulic speed control for turbines to advanced alternatives. Many old installations have been upgraded to dry gas seals and electronic governors. However, few changes have been made to the combined oil systems, leaving the system overdesigned for its new purpose and presenting an energy optimization opportunity. Optimization solutions to existing systems vary depending on system requirements; however, the solutions discussed in this article include utilizing a lower-speed motor, magnetic coupling, recycle line and resizing the pump.

Turbomachinery oil systems can be categorized into three categories: lubrication oil, seal oil and control oil. A lubrication oil system aims to continuously provide clean-cool oil at the required pressure, temperature and flowrate to the hydrodynamic bearings and gears (if applicable). Typically, oil is supplied with a pressure in the range of 1 barg–2 barg, but the required flow to each bearing varies depending on bearing size and equipment speed.

Seal oil systems are similar to lube oil systems and, in many cases, combine into a single system. A seal oil system provides cool-clean oil to the seals at the required temperature, flowrate and differential pressure compared to a gas reference pressure. The pressure at which the seal oil is supplied varies depending on the machine's discharge pressure, but it is much higher than that of lubrication oil and with a fraction of the lubrication oil flow.[1]

Control oil is used on turbines to supply hydraulic power to the inlet valve actuators, which regulate the turbine speed based on the valve position as it
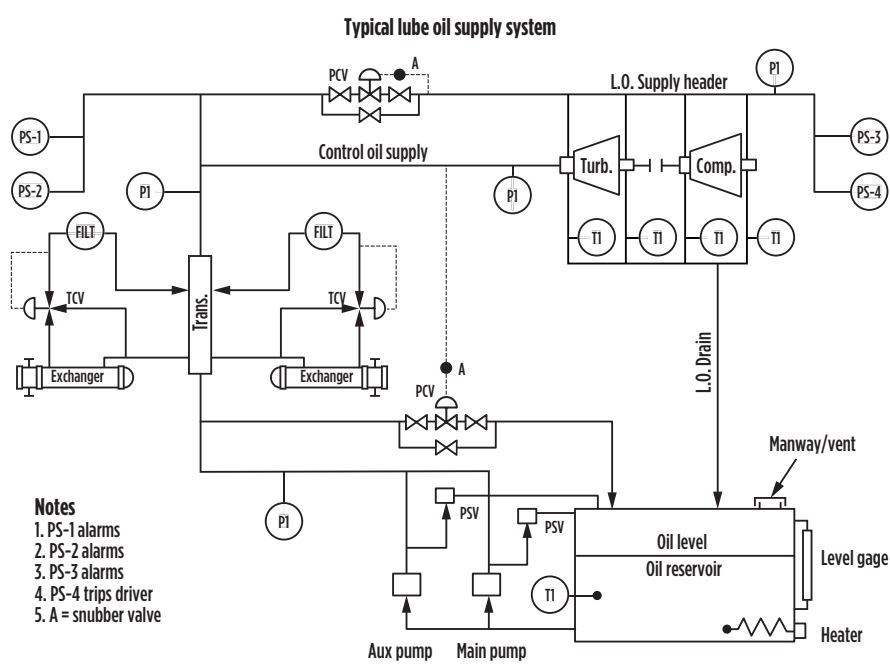

FIG. 1. Lube oil supply system. Courtesy of M.E. Crane Consultant.

controls the flow of gas or steam supplied to the turbine.

The first step in optimizing the system is to determine the current oil requirement regarding flow and pressure. Once established, the options below should be explored and evaluated based on economic benefits.

Lower-speed motor. This option is applicable to systems with rotary oil pumps if the system demand pressure remains the same but the required flow is reduced. The capacity of rotary pumps is linearly proportional to shaft speed, and they provide whatever discharge pressure the system requires. Therefore,

operating a motor at half speed will provide half of the flow at the same pressure. This is an excellent and simple modification if a large quantity of oil is not required, allowing for a lower horsepower (hp) motor since the flow is lower. The downside of this option is that motor speed choices are limited to certain rpm, depending on the motor's frequency and the number of poles, which restricts the system enhancement.

Permanent magnet shaft coupling. This option is also applicable to systems with rotary oil pumps and reduced flow demand. The permanent fixed-gap magnetic coupling allows the pump speed to

be lowered to any required value based on the coupling separation gap set at installation. The magnetic coupling takes up a large amount of space compared to other traditional rigid or flexible couplings. This challenges vertical submerged lube oil pumps where space at the coupling section is restricted.

Resizing pressure control/adding recycle line. This option is applicable
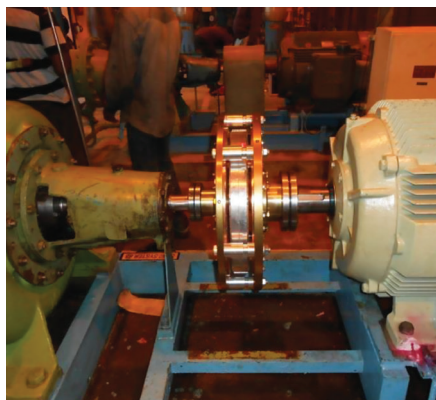

FIG. 2. Rotary oil pump. Courtesy of Magnadrive.

to systems that require a similar flow but at a lower pressure requirement (e.g., removal of seal oil). Resizing the backpressure control valve to reduce the oil header pressure will result in lower power demand from the pump. This option solves some obsolescence issues for high-pressure wet seal compressors, as high-pressure oil controllers are no longer manufactured and almost all new compressors are equipped with dry gas seals. In some cases, an additional recycle line with an orifice can be a more economical solution to avoid replacing the backpressure controller while maintaining the controllability range of the existing valve.

Pump resize. This option is the last resort since it requires the largest investment, but it can be economically justified based on the size of the pump, energy cost, pump reliability and maintenance cost history.

Case study. A 28,000-hp steam turbine driving a gas compressor in a gas

plant was upgraded from hydraulic to electronic governor, while the compressor was upgraded from oil seal to dry gas seal. The machine was equipped with a combined lube-control-seal oil system. The combined system's rotary oil pump rated capacity is 229 gpm (gal/min) and is driven by a 100-hp motor at 1,800 rpm, while the combined oil system header is controlled at 300 psig. Without the governor and seal oil, the current system only requires lubricating oil to the bearings, which need only 118 gpm of oil at 20 psig.

Replacing the existing motor with one of the same frame size but with two-thirds of the speed (1,200 rpm) would yield two-thirds of the rated flow (152 gpm), which is the required flow to the bearings plus a 25% margin. The header pressure could be lowered to approximately 100 psig, which will be controlled further to 20 psig at the bearings. These changes would reduce the power requirement on the motor from 100 hp to 25 hp. This optimization solution results in 75% yearly power savings by replacing the motor with a lower-speed model and reducing the discharge pressure on the pump. **HP**

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